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54.17

NLS2009040
June 15, 2009

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555-0001

Subject: Response to Request for Additional Information for License Renewal Application – Aging Management Programs
Cooper Nuclear Station, Docket No. 50-298, DPR-46

References:
1. Letter from Tam Tran, U.S. Nuclear Regulatory Commission, to Stewart B. Minahan, Nebraska Public Power District, dated May 1, 2009, "Request for Additional Information for the Review of the Cooper Nuclear Station License Renewal Application (TAC No. MD9763 and MD9737)."
2. Letter from Stewart B. Minahan, Nebraska Public Power District, to U.S. Nuclear Regulatory Commission, dated September 24, 2008, "License Renewal Application."

Dear Sir or Madam:

The purpose of this letter is for the Nebraska Public Power District to respond to Section B.2 of the Nuclear Regulatory Commission Request for Additional Information (RAI) (Reference 1) related to the Cooper Nuclear Station License Renewal Application (LRA) Aging Management Programs (AMP). These responses are provided in Attachment 1. Certain changes to the LRA (Reference 2) have been made to reflect these RAI responses. These changes are provided in Attachment 2 and include any necessary changes to the Updated Safety Analysis Report supplement provided in Appendix A to the LRA. The commitments made in this submittal supplement the commitments made in the LRA to the development of new and enhanced AMPs. For purposes of clarity, these supplemental commitments are appended to the original commitment for a particular AMP in the attached commitment tracking form.

Should you have any questions regarding this submittal, please contact David Bremer, License Renewal Project Manager, at (402) 825-5673.

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NRR

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 6/15/09
(Date)

Sincerely,

Stewart B. Minahan
Vice President – Nuclear and
Chief Nuclear Officer

/wv

Attachments

cc: Regional Administrator w/ attachments
USNRC - Region IV

Cooper Project Manager w/ attachments
USNRC - NRR Project Directorate IV-1

Senior Resident Inspector w/ attachments
USNRC - CNS

Nebraska Health and Human Services w/ attachments
Department of Regulation and Licensure

NPG Distribution w/o attachments

CNS Records w/ attachments

ATTACHMENT 3 LIST OF REGULATORY COMMITMENTS©[4]

Correspondence Number: NLS2009040

The following table identifies those actions committed to by Nebraska Public Power District (NPPD) in this document. Any other actions discussed in the submittal represent intended or planned actions by NPPD. They are described for information only and are not regulatory commitments. Please notify the Licensing Manager at Cooper Nuclear Station of any questions regarding this document or any associated regulatory commitments.

COMMITMENT	COMMITMENT NUMBER	COMMITTED DATE OR OUTAGE
Implement the aboveground Steel Tanks Program. [LRA Section B.1.1] The thickness measurements will be performed at least once during the first ten years of the period of extended operation and periodically thereafter. The results of the initial inspection will be used to determine the frequency of subsequent inspections. [RAI B.1.1-1]	NLS2008071-01 (Revision 1)	January 18, 2014
Enhance the Containment Inservice Inspection Program to add examination of required accessible areas using a visual examination method and surface areas not accessible on the side requiring augmented examination to be examined using an ultrasonic thickness measurement method in accordance with IWE-2500(b). Enhance the program to document material loss in a local area exceeding 10% of the nominal containment wall thickness or material loss in a local area projected to exceed 10% of the nominal containment wall thickness before the next examination in accordance with IWE-3511.3 for volumetric inspections. [LRA Section B. 1.10] To ensure the [drywell sand cushion drain] lines are obstruction free, a vacuum test of all eight sand bed drain lines will be performed prior to the period of extended operation (PEO). [RAI B.1.10-1]	NLS2008071-05 (Revision 1)	January 18, 2014

Enhance the Diesel Fuel Monitoring Program to include the use of ASTM Standard D4057 for sampling of the diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to include periodic visual inspections and cleaning of the diesel fuel oil day tanks, the diesel fuel oil storage tanks, and the diesel fire pump fuel oil storage tank. Enhance the program to include periodic multilevel sampling of the diesel fuel oil day tanks and the diesel fire pump fuel oil storage tank and to include periodic visual inspections as well as ultrasonic bottom surface thickness measurement of the diesel fuel oil day tanks, the diesel fuel oil storage tanks, and the diesel fire pump fuel oil storage tank. Enhance the program to provide the acceptance criterion of ≤ 10 mg/l for the determination of particulates in the diesel fire pump fuel oil storage tank. Enhance the program to specify acceptance criterion for UT thickness measurements of the bottom surfaces of the diesel fuel oil day tanks, the diesel fuel oil storage tanks, and the diesel fire pump fuel oil storage tank. [LRA Section B.1.12] The acceptance criteria for UT measurement of tank bottom thickness for the referenced diesel fuel tanks will be based on component as-built information adjusted for corrosion allowance. If measurements show less than the minimum nominal thickness less corrosion allowance, engineering will evaluate the measured thickness for acceptability under the corrective action program. Evaluation will include consideration of potential future corrosion to ensure that future inspections are scheduled before wall thickness becomes unacceptable. [RAI B.1.12-1]	NLS2008071-06 (Revision 1)	January 18, 2014

Consideration of the effect of the reactor water environment will be accomplished through implementation of one or more of the following options for the feedwater nozzles, core spray nozzles and RHR pipe transition. (1) Update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case). [LRA Section B.1.15] (2) Repair or replace the affected locations before exceeding an environmentally adjusted CUF of 1.0. [RAI B.1.15-1] The CNS Fatigue Monitoring Program will be enhanced to require the recording of each transient associated with the actuation of a safety/relief valve (SRV). [LRA Section B.1.15]	NLS2008071-08 (Revision 1)	January 18, 2014
Enhance the Flow-Accelerated Corrosion Program to update the System Susceptibility Analysis for this program to reflect the lessons learned and new technology that became available after the publication of NSAC-202L Revision 1. [LRA Section B. 1.18] Program guidance documents will be revised to stipulate requirements for training and qualification of non-CNS personnel involved in implementing the FAC program. [RAI B.1.18-3]	NLS2008071-11 (Revision 1)	January 18, 2014

Attachment 1

Response to Request for Additional Information
for License Renewal Application – Aging Management Programs
Cooper Nuclear Station, Docket No. 50-298, DPR-46

The Nuclear Regulatory Commission (NRC) Request for Additional Information (RAI) regarding the License Renewal Application Aging Management Programs are shown in italics. The Nebraska Public Power District's (NPPD) response to each question is shown in block font.

NRC Request: *RAI 3.0-1*

Background

Several of the aging management programs proposed by Cooper Nuclear Power Station are described as "new". These programs do not include operating experience. While the staff acknowledges the fact that theses programs are new and that no operating experience with these programs exists per se, there may be plant or industry activities or operating experience which may be relevant to the development of these new programs. In addition, the Branch Technical Position, RLSB-1 (SRP Appendix A.1) states that "the applicant may have to commit to providing operating experience in the future for new programs to confirm their effectiveness."

Issue:

The staff finds it difficult to evaluate the sufficiency of the proposed new aging management programs in the absence of operating experience.

Request:

For each of the aging management programs designated as "new", please provide operating experience related to the subject of the aging management program. Operating experience should provide a sufficient basis to support adequacy of the new aging management programs. Information should be provided for the following programs which were identified in the LRA as new programs:

- *(a) Above Ground Tanks (B.1.1)*
- *(b) Buried Piping and Tanks Inspection (B.1.3)*
- *(c) Metal Enclosed Bus Inspection Program (B.1.22)*
- *(d) Non Environmentally Qualified Bolted Cable Connections (B.1.24)*
- *(e) Non Environmentally Qualified Medium Voltage Cable (B.1.25)*
- *(f) Non Environmentally Qualified Circuits Test Review (B.1.26)*
- *(g) Non Environmentally Qualified Insulated Cables and Connections (B.1.27)*

(h) *One Time Inspection (B.1.29)*
(i) *One Time Inspection of Small Bore Piping (B.1.30)*
(j) *Selective Leaching (B.1.34)*
(k) *Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (B.1.37)*

Additionally, for each of the new programs please commit to providing future operating experience.

NPPD Response:

The new aging management programs at Cooper Nuclear Station (CNS) are programs described in NUREG-1801. By definition, industry operating experience forms the basis for NUREG-1801, as evidenced by the title "Generic Aging Lessons Learned Report." There is no operating experience with the programs yet to be implemented (new programs) described in CNS License Renewal Application (LRA) Appendix B, although there may be plant or industry activities or operating experience which may be relevant to the implementation of these new programs. This relevant operating experience will be used in the implementation of these new programs. For example, the Non-EQ Bolted Cable Connections Program described in LRA Section B.1.24 is a new one-time inspection program, and as such it is modeled after the One-Time Inspection Program listed in NUREG-1801, Section XI.M32. Therefore, industry activities and operating experience for these new CNS programs is provided in the "Operating Experience" element of NUREG-1801 for each of the new program descriptions.

During the operating experience review of the individual plant assessment, NPPD evaluated plant and industry operating experience to identify aging effects, if any, that differed from those addressed in industry guidance documents including NUREG-1801. No such new aging effects were identified. The new NUREG-1801 programs described in the CNS LRA are credited only for the same aging effects for which NUREG-1801 credits the specific program.

In summary, aging effects for which new CNS programs are credited are the same aging effects for which NUREG-1801 credits the same program. The new programs are not credited to manage aging effects for which the program was not evaluated in NUREG-1801. NUREG-1801 programs are based on industry-wide operating experience. No CNS-specific operating experience was identified that would lead to the conclusion that the proposed aging management programs will not be effective in managing the aging effects for which they are credited. This consideration of plant-specific and industry operating experience provides reasonable assurance of the sufficiency of the proposed new aging management programs.

With regard to future operating experience, an operating experience review program currently exists at CNS. This program monitors industry-wide operating experience from a number of sources (e.g., Institute of Nuclear Power Operations (INPO) reports and NRC Information

Notices). Each item is reviewed for applicability to CNS. Applicable items are assigned to a responsible individual as a corrective action under the CNS corrective action program. This process assures proper evaluation of operating experience. In addition, LRA Section B.0.3 indicates that each new aging management program includes program elements for corrective actions and confirmation process that are consistent with the recommendations of NUREG-1801. These program elements will generate actions to preclude recurrence of any deficiencies in CNS aging management programs which may be revealed through operating experience (both plant-specific and industry-wide). These program elements are applicable on an ongoing basis, providing a feedback mechanism based on operating experience that ensures continuing program effectiveness throughout the period of extended operation (PEO). The corrective action process is an established process subject to ongoing routine oversight by full-time NRC inspectors at the plant site. This ongoing process to monitor industry and site operating experience, including mechanisms to update or modify plant procedures or practices to incorporate lessons learned, assures the effectiveness of the procedures or practices to incorporate lessons learned, assures the effectiveness of the development and maintenance of the new CNS programs through the PEO. Accordingly, NPPD contends that a commitment to submit future operating experience on the new programs is unnecessary.

NRC Request: *RAI 3.1.2-1*

Background:

In LRA Table 3.1.2-2 (page 3.1-52) and Table 3.3.1, item 3.3.1-47, the applicant states that the loss of material due to pitting and crevice corrosion in the shroud support is managed by the Water Chemistry Control – BWR Program and the effectiveness of the water chemistry program will be confirmed by the One-Time Inspection Program. The applicant also states that the Inservice Inspection – ISI Program of the LRA is not applicable to most reactor vessel internals components since they are not part of the pressure boundary.

Issue:

In contrast, the ASME Section XI inservice inspection requires periodic visual inspections for integrally welded core support structures and interior attachments to reactor vessels as described in Examination Category B-N-2.

It is not clear why the applicant does not credit the Category B-N-2 examination for the loss of material in the core shroud support.

Request:

Clarify whether the applicant performs the Category B-N-2 examination. Provide further justification why the water chemistry program is adequate to manage the loss of material without further periodic inspections.

NPPD Response:

CNS performs periodic visual inspections of integrally welded core support structures and interior attachments to the reactor vessel, as prescribed in ASME Section XI, Inservice Inspection (ISI) Examination Category B-N-2. These inspections could be credited, along with water chemistry, to manage loss of material for the portions of the shroud support inspected under the ISI program. However, for consistency with the management of loss of material for the remainder of the vessel internals (including portions of the shroud support not subject to ISI), only water chemistry and the one time inspection program are credited.

NUREG-1801 recognizes the combination of water chemistry and one time inspection programs, without further periodic inspections, as an acceptable means of managing loss of material for stainless steel and nickel alloy in reactor coolant. NUREG-1801, Volume 2, items IV.A1-8, IV.B1-15, and IV.C1-14 address this material, environment and aging effect combination for reactor vessel components, vessel internals components, and reactor coolant pressure boundary components respectively. Items IV.A1-8 and IV.C1-14, for the vessel and reactor coolant pressure boundary components both identify water chemistry and one time inspection as the applicable aging management programs for loss of material. Periodic inspections by ISI for these pressure boundary components are needed for management of cracking, not loss of material. Only item IV.B1-15 includes the ISI program for management of loss of material. Since the aging effect of loss of material is managed by water chemistry and one time inspection per items IV.A1-8 and IV.C1-14 for an identical material and environment, it is reasonable to conclude that aging management of non-pressure boundary components will also be effective with this combination of programs.

NRC Request: *RAI 3.3.1-1*

Background:

In the LRA, the GALL Report Reactor Water Cleanup System (RWCU) AMP is not credited for the aging management of the stainless steel IGSCC in the RWCU system. Instead, the Water Chemistry Control Program in conjunction with the One-Time Inspection Program was credited to manage the aging effect. The approach of the applicant might cause no further periodic inspections on the RWCU System.

The GALL Report recommends the following three criteria should be met to discontinue the IGSCC inspection of the RWCU system piping welds outboard of the second isolation valve:

(a) *Satisfactory completion of GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance"*

(b) *No IGSCC detected in RWCU piping welds inboard of the second isolation valve (ongoing GL 88-01 inspection)*

(c) *No IGSCC detected in RWCU piping welds outboard of the second isolation valve after inspecting a minimum of 10 percent of the susceptible piping welds*

The LRA Table 3.3.1, item 3.3.1-37, indicates:

- *The applicant has complied with the requirements of GL 89-10*
- *Portions of the RWCU System were replaced with a SCC-resistant material*
- *No significant indications of SCC were observed on the piping that was not replaced*

Issue:

It is not clear whether the applicant met all of the three criteria to discontinue the RWCU system inspections.

Request:

(a) *Clarify whether all of the three criteria are met to discontinue the inspections of the outboard piping of the RWCU system.*

(b) *If all of the three criteria are not met, clarify what inspections will be performed for the inboard and outboard portions of the RWCU system piping, respectively, over the extended period of operation.*

NPPD Response:

Background

As described in a January 2, 1997 letter from P. D. Graham to NRC[1], the inspections of the outboard piping of the RWCU system, under the program outlined in NUREG-0313 and Generic Letter (GL) 88-01, were discontinued based on the staff positions presented in Supplement 1 to

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[1] NLS960226, P. D. Graham to USNRC, "Non-safety Related Reactor Water Cleanup Austenitic Stainless Steel Piping Welds," January 2, 1997.

GL 88-01. CNS demonstrated compliance with the requirements of GL 89-10, and found no indication of intergranular stress corrosion cracking (IGSCC) during the inspection of more than 10% of the welds on RWCU piping that had not been replaced with IGSCC resistant materials. This eliminated the requirement for augmented ISI inspection of the outboard RWCU piping from the CNS current licensing basis.

The screening criteria given in the Scope of Program section of NUREG-1801, XI.M25, which are based on a letter from the NRC to Peach Bottom, provide an interpretation of the requirements in NUREG-0313, Rev. 2, and GL 88-01. As listed in RAI 3.3.1-1, NUREG-1801, XI.M25 recommends the following three criteria should be met to discontinue the IGSCC inspection of the RWCU system piping welds outboard of the second isolation valve:

(a) Satisfactory completion of GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance"

(b) No IGSCC detected in RWCU piping welds inboard of the second isolation valve (ongoing GL 88-01 inspection)

(c) No IGSCC detected in RWCU piping welds outboard of the second isolation valve after inspecting a minimum of 10 percent of the susceptible piping welds

In addition to these three criteria, NUREG-1801, XI.M25 also provides the following option (underlined for clarity and emphasis):

> "No IGSCC inspection is recommended for plants that meet all the above three criteria <u>or that meet criterion (a) and piping is made of material that is resistant to IGSCC.</u>"

a) <u>Clarification of how CNS meets the criteria of NUREG-1801, Section XI.M25</u>

Criterion (a) – CNS completed the actions associated with GL 89-10 on motor-operated valves. Therefore, criterion (a) has been met.

Criterion (b) – The piping inboard of the second isolation valve (four inch or greater, at or above 200 °F) has been replaced with IGSCC resistant material, which, on the basis of the additional option above, effectively satisfies criterion (b).

Criterion (c) – Some RWCU piping (four inch or greater, at or above 200 °F) outboard of the second isolation valve has been replaced with IGSCC resistant material. The replaced piping has no susceptible welds. Of the remaining RWCU piping outboard of the second isolation valve, an inspection of more than 10% of the welds found no indication of IGSCC, which satisfies criterion (c).

Therefore, all three criteria are met to discontinue the inspections of the outboard piping of the RWCU system.

b) Not applicable. All of the three criteria are met.

NRC Request: *RAI 4.3-1*

Background:

In Section 4.3 of the LRA, it states that "If the component has a fatigue TLAA that remains valid (i) or is projected to cover the period of extended operation (ii), then cracking due to fatigue is not an aging effect requiring management for those components during the period of extended operation".

Issue:

If cracks developed while the TLAA has concluded that the component is qualified for either 10 CFR 54.21(c)(1)(i) or 10 CFR 54.21(c)(1)(ii), then it is most likely because either the TLAA results have been questionable or the pre-operational inspection results and handling of the inspection results have been questionable. Cracking is a major safety issue for any operating structural components. Immediate remedial actions must be taken for cracks that are detected at any time.

Request:

The statement quoted under the Background subtitle above implies that cracking could be ignored as long as the stated conditions are met. Provide the basis to justify this statement and discuss how CNS would handle the situation

NPPD Response:

The statement quoted above reflects the provisions of 10 CFR 54.21(c) which indicates that an aging management program is not required if a time-limited aging analysis (TLAA) remains valid or is projected through the PEO. The implication is that the reason no aging management program is required is that the associated aging effect does not require management. If new cracks are found during normal operation or surveillances, the condition is immediately documented in the corrective action program and appropriate corrective actions are taken.

NRC Request: *RAI 4.3-2*

Background:

In Section 4.3 of the LRA, it states that "... flaw indications discovered during inservice inspection are TLAA for those analyses based on time-limited assumptions defined by the current operating term.... A review of such flaw growth analyses for CNS has identified none that are TLAA".

Issue:

The statement quoted above hints that CNS has discovered flaw indications, and those indications were not revealed during inservice inspections. Then, these indications most likely were discovered during the plant pre-operational phase.

Request:

(a) *Clarify whether there were flaw indications during the ISI. If the indications were discovered during the pre-operational phase, what remedial or corrective actions have been taken?*

(b) *If flaw indications were discovered, describe the geometry of the flaws, including flaw size, flaw orientation, component, analysis method used, repair and disposition.*

(c) *Elaborate on the last part of the above quoted statement, i.e., "A review of such flaw growth analyses for CNS has identified none that are TLAA".*

NPPD Response:

(a) The subject flaw indications were found during ISI, not during pre-operational inspection. See response to (c) below for details.

(b) See response to (c) for description of flaws found to date.

(c) During the preparation of the LRA, NPPD reviewed the plant ISI records and identified flaws that had been found and not repaired or replaced. Evaluations of these flaws were then reviewed and no TLAAs were found. The following flaw indications were identified:

Feedwater Nozzle to Vessel Welds

During 1991, ISI on the feedwater nozzles found indications in feedwater nozzle to vessel welds N4A, N4C, and N4D. Further evaluation under Section XI of the ASME Code was performed. NPPD submitted a fracture mechanics analysis for the nozzle forging to vessel weld using an RT_{NDT} of 30 °F (letter NLS9100849, G. R. Horn to U.S. NRC dated December 20, 1991, "Indications in Feedwater Nozzle to Vessel Welds N4A, N4C, and N4D," which includes GENE-523-133-1191, Rev. 1 as an attachment). The calculated available fracture toughness remained well in excess of the required fracture toughness. The analysis did not consider feedwater thermal sleeve bypass leakage, and explains that was not necessary as recent ultrasonic test (UT) examination revealed no evidence of thermal fatigue cracking.

GENE-523-133-1191 analyzed crack growth based on 120 startup cycles and 600 thermal/pressure cycles. At the time (1991), 120 startups were the allowable numbers for vessel transients. However, when the allowable vessel transients (Updated Safety Analysis Report (USAR) Table III.3-1) were increased to the current limits, the transient numbers used in GENE-523-133-1191 no longer bounded 40 years of operation.

Although the original analysis was done based on an assumed 40-year number of transients, the analysis is not being used to justify operation of the nozzle for the remainder of plant life. The nozzle continues to be inspected each 10-year ISI interval. As such, this analysis is not a TLAA.

Main Steam Nozzle (N3A) to Vessel Weld

During the fall 1998 refueling outage (RFO-18), an indication was identified in the main steam nozzle to vessel weld N3A that exceeds the acceptance criteria of IWB-3512. This indication had been incorrectly identified in 1976 and 1986 as being in the nozzle forging. The 1998 examination identified that the indication was in the forging to vessel weld (this indication is similar to the feedwater nozzle indications). A fracture mechanics evaluation of this indication (GE-NE-B13-01980-24) was submitted to the NRC (Letter NLS980182, M. F. Peckham to U.S. NRC, "Main Steam Nozzle to Shell Weld Fracture Mechanics Evaluation," October 30, 1998).

Section 5.6 of GE-NE-B13-01980-24 calculates the flaw growth based on 120 startup/shutdown cycles. Although the original analysis was done based on an assumed 40-year number of transients, the analysis is not being used to justify operation of the nozzle for the remainder of plant life. The nozzle continues to be inspected each 10-year ISI interval. As such, this analysis is not a TLAA.

Reactor Vessel Shell Indication

NPPD analyzed indications found in the reactor vessel shell during the 1998 refueling outage. That analysis states: "PIR 3-50914 (Condition Report CR98-0882) documented the condition that ultrasonic testing (UT) of the Reactor Pressure Vessel (RPV) welds VLA-BA-3 and BLC-BB-2 indicated that some flaws exceeded the IWB-3500 flaw allowable size requirements of ASME Code Section XI. The purpose of this evaluation is to evaluate the unacceptable flaws in the welds to the requirements of IWB-3600 of the ASME Code, Section XI and to provide closure to the PIR. The unacceptable indications documented in GE's data report numbers RPV-03 and RPV-10 are the subject of this evaluation."

There were a total of 62 indications in these two welds. The indications were close to mid-plane and appeared to be fabrication related. The indications were evaluated against IWB-3500 and a few failed and were therefore evaluated against IWB-3600. These evaluations included various time frames (the 40-year license term of the plant, 16 effective full power year (EFPY), etc.), but were not used to justify the vessel for the remaining 40-year license term. They were used to justify the vessel until the next inspection, and thus were not TLAA.

After supplemental UT, the sizes of the flaws were found to be within the limits of IWB-3500. A flaw evaluation per IWB-3600 was not performed, thus there is no TLAA associated with these indications.

Core Spray Piping Indications

Indications were found at core spray piping welds P1, P8a, P8b and P9. These inspections were performed per Boiling Water Reactor Vessel and Internals Project (BWRVIP) guidelines and are not ASME pressure boundary welds. The analysis determined the acceptance criteria of BWRVIP-18 were met until the next inspection. The evaluation is not based on the life of the plant and therefore is not a TLAA.

An indication in a hidden weld in the core spray piping internal to the vessel was also found and evaluated. This was not an ASME code weld, and so was not evaluated per that code. The indication was observed during a BWRVIP inspection of the core spray piping inside the vessel. The evaluation determined the expected flaw growth by the subsequent inspection and showed that it is well below the allowable flaw size. The evaluation is not based on the life of the plant and therefore is not a TLAA.

Core Shroud Indications

Indications in multiple shroud welds were observed in January 2005 and were re-inspected in November 2006. These were not ASME code welds, and so were not evaluated per that code. The welds were inspected based on BWRVIP guidelines and were evaluated according to BWRVIP-76, including plant-specific evaluations per BWRVIP-94. The evaluation showed the shroud to be acceptable without additional inspections for at least 10 years. The evaluation is not based on the initial 40-year operating term and therefore is not a TLAA.

NRC Request: *RAI 4.3.1-1*

The NRC communicated that a revision to this RAI would be sent in a future letter. No NPPD response is required at this time.

NRC Request: *RAI 4.3.1-2*

Background:

In LRA Table 4.3-1, under the 1st Column, Transient Description, the 5th item is shown as "Turbine roll (assumed same as startup)".

Issue:

This transient description requires clarification.

Request:

(a) *Please clarify why Turbine Roll transient is assumed to be same as Startup transient. What are involved in the assumption and why is it necessary to make such an assumption?*

(b) *Describe the differences between the Turbine Roll and Startup transients and the relationship between the two.*

NPPD Response:

(a) Turbine roll transient is not assumed the same as the startup transient; however, due to the relationship between the two, the number of occurrences for the turbine roll transient is assumed the same as the number of occurrences counted for the startup transient. The intent of the referenced item in LRA Table 4.3-1 was to reflect that the number of occurrences of the transients is assumed to be the same. Startup takes the plant from ambient conditions to 546 °F. Turbine roll occurs after startup and continues until the plant reaches 100% power. The allowable limit for number of turbine rolls is the same as the limit for startups. Ideally every startup is followed by an increase to 100% power. Since it is assumed there is one turbine roll per startup, the transient is not listed in USAR Table III-3-1.

(b) Startup is the increase in temperature of the reactor coolant system (RCS) from ambient to 546 °F, while turbine roll is the warmup and loading of the main turbine, which occurs at the end of the startup transient.

NRC Request: *RAI 4.3.1-3*

Background:

LRA Table 4.3-1 provides the transients types and their respective cycles and 60-year projected number of cycles, based on which fatigue evaluations were made.

Issue:

The LRA does not correlate LRA Table 4.3-1 to the proper section of the USAR of CNS. While USAR Table III-3-1 shows the reactor vessel thermal cycles, description of the transients and their associated cycles is not quite consistent with the transient names and the cycles shown in LRA Table 4.3-1.

Request:

(a) Turbine roll, hot standby (feedwater cycling), pipe rupture and blowdown, OBE, safety/relief valve actuations, and core spray injection transients were not listed in USAR Table III-3-1. Were these transients considered in the original stress and fatigue analyses? If not, how could you make a 60-year projection since the fatigue TLAA for license renewal and the original fatigue analysis have different basis? In addition, if not considered in the original analyses, how could you have satisfied the ASME III stress qualification and fatigue requirements in the first 40-year term license application?

(b) According to LRA Table 4.3-1, since the ratios of the 60-year projected cycles to the design cycles are distinct for each transient, there exists no single constant for making a quick and simple 60-year CUF projection. Please describe how CNS obtained the 60-year CUF values reported in Table 4.3-3.

NPPD Response:

(a) The major transients analyzed for the reactor vessel were listed in USAR Table III-3-1, and Technical Specification 5.5.5 requires counting of these reactor vessel transient cycles. Because these design cycles represent the significant thermal transients (normal and upset) foreseen for the reactor vessel, analysis of these transients satisfied the ASME III fatigue requirements for the reactor vessel.

Fatigue analyses of other components considered the transients that the designers foresaw for those components. For some components other than the reactor vessel, additional transients not listed in the USAR are also counted by this program.

The following paragraphs address cycle counting for the transients identified in this RAI that are not listed in USAR Table III-3-1.

Turbine roll – One turbine roll is assumed following every startup. Therefore, a specific listing for turbine roll in USAR Table III-3-1 was not provided to assure validity of the vessel fatigue analysis.

Hot standby (feedwater cycling) constitutes two additional temperature excursions due to on/off cycles of feedwater for each shutdown. This was assumed concurrent with each shutdown so a specific listing of this transient was not provided in USAR Table III-3-1.

Pipe rupture (loss-of-coolant accident (LOCA)) is a faulted condition, not a normal or upset condition, and hence, need not be included in an ASME fatigue analysis of Class 1 components. Operating Basis Earthquake was included in the fatigue calculations but was not tracked in the Fatigue Monitoring Program since it is not an operational transient as defined in the CNS USAR.

Safety/relief valve actuations are not a factor in the reactor vessel fatigue analyses, but are a factor in the containment fatigue analyses. CNS includes them in the cycle counting procedure.

Core spray injections – One cycle of core spray injection was included in the original analysis of the core spray nozzle. There have been no injections of core spray with the vessel at operating conditions. CNS is including one cycle in the environmentally assisted fatigue analyses for license renewal.

The appropriate transients were considered in the current licensing basis fatigue calculations. Those same transients were considered when evaluating fatigue TLAAs for license renewal.

(b) It is correct that there is no single factor that extends all 40-year cumulative usage factors (CUF) to 60-year CUFs. As discussed in LRA Section 4.3.3, CNS first projected the operating cycles through 60 years, based on the numbers of cycles to date. Then the CUF was recalculated using the projected operating cycles. The recalculation for environmentally assisted fatigue also removed additional conservatism as discussed in response to RAI 4.3.1-7.

The projection of cycles was not done by a simple ratio of years, but was unique for each event, as supported by operating data. When operating data indicated that the projection of future cycles would be more accurate if based on recent data rather than the life of the plant, then recent data was used. Operation of CNS is similar to most other commercial nuclear power plants. The rate of incurring cycles in the early years of plant life was typically higher than the rate of incurring cycles in later years of plant life. This is due to the accumulation of industry operating experience, increased emphasis on reliable operation, and good practices promulgated by plant vendors and industry groups. Determination of the 60-year CUF values in LRA Table 4.3-3 relied on realistic transient cycle projections. Continuing execution of the Fatigue Monitoring Program and ensures analyses based assumed numbers of transient cycles will remain valid through the PEO.

NRC Request: *RAI 4.3.1-4*

Background:

LRA Section 4.3.1.1 discusses the TLAA for the Reactor Vessel. It indicates that the fatigue analysis involved measurement uncertainty recapture (MUR) power uprate in the spring of 2008. In this Section, the LRA states that "... Results of these analyses have been submitted to the NRC as part of the MUR request. Fatigue analyses for several locations were done using modern techniques and removing some conservatism that resulted in significantly lower CUFs".

Issue:

Clarifications are necessary as described below.

Request:

(a) Describe the modern techniques used for these analyses.

(b) Describe the conservatism which was removed in the new analyses and show differences between the new and old analysis results.

NPPD Response:

(a) The evaluation for all locations used finite element analyses that include modern-day fatigue calculations performed in accordance with the 1998 Edition, 2000 Addenda of the ASME Code. This involved applying a Young's Modulus correction factor (i.e., $E_{fatigue}$ curve/$E_{analysis}$) to the calculated stresses, applying K_e where appropriate, and utilizing the 2000 Addenda fatigue curve.

(b) The previous CUF of record and the revised Measurement Uncertainty Recapture (MUR) CUF for reanalyzed components are listed below. The MUR analyses were previously submitted to the NRC in a letter from Stewart B. Minahan (NPPD) to U.S. NRC Document Control Desk, "License Amendment Request to Revise Technical Specifications - Appendix K Measurement Uncertainty Recapture Power Uprate," dated November 19, 2007. This was accepted by the NRC in License Amendment 231, dated June 30, 2008.

Component	Previous CUF	MUR CUF
Vessel shell	1.008	0.1033
Closure stud	0.83	0.977
Recirc outlet nozzle	0.839	0.0144
Control rod drive penetrations	0.92	0.8632
Shroud support plate	0.567	0.0151

The removed conservatism that resulted in reduction to some CUF values was primarily the method of evaluating transients. Earlier analyses summed the numbers of all transients and evaluated them all as the most severe transient. Ungrouping the transients and separately evaluating the less severe transients led to significantly lower fatigue usage. Additional conservatism was removed by changing from the assumed numbers of cycles in original analyses to more realistic projected numbers of cycles based on actual plant operating history.

NRC Request: *RAI 4.3.1-5*

Background:

LRA Section 4.3.1.2.2 discusses feedwater nozzle cycles analyzed. It first discussed the feedwater on/off cycles and then followed by a discussion of feedwater rapid cycling.

Issue:

Clarifications are necessary as described below. In addition, the feedwater rapid cycling transient is not included in LRA Table 4.3-1.

Request:

(a) *For the feedwater on/off cycles, the LRA states that CNS does not monitor these transients but assumes 6 cycles per shutdown. Please confirm this assumption is conservative by reviewing the records of actual cycles logged and calculate average cycles to date to compare with the assumed value of 6 cycles per shutdown.*

(b) *For the Feedwater rapid cycling, the LRA states that "...based on years of operation, and the number of analyzed years (40) will be exceeded during the period of extended operation". However, the feedwater rapid cycling transient is not included in LRA Table 4.3-1. Please explain why it is not included in LRA Table 4.3-1 and appropriately reflect it in Table 4.3-1.*

(c) *Describe the differences between the feedwater on/off cycles and the feedwater rapid cycling transients. Per the discussion in LRA Section 4.3.1.2.2, these are two different types of thermal events and none of these thermal events is included in USAR Table III-3-1. Then just like discussed in RAI 4.3.1-3, how could you make a 60-year projection since the fatigue TLAA for license renewal and the original fatigue analysis have different basis? Again, how could you have satisfied the ASME III stress qualification and fatigue requirements in the first 40-year term license application?*

NPPD Response:

(a) CNS indirectly accounts for the feedwater (FW) on/off cycles by counting the concurrent events of startup and shutdown. There are no records of actual cycles logged since CNS does not monitor these transients.

During low power operations, FW flow is controlled by the FW startup flow control valves. The FW startup flow control valves operate in an automatic mode allowing the FW system to maintain constant reactor vessel level with a small but stable FW flow. This mode of operation minimizes the need to start and then stop FW flow to maintain level, which is the transient that constitutes a FW on/off cycle.

Because of this mode of operation, that is, using startup flow control valves to control reactor vessel level at low power levels, the assumption of six cycles per shutdown is conservative.

(b) As indicated in the LRA, the effects of FW rapid cycling are included in the fatigue analysis for the FW nozzle based on operating time in years of operation. It is not possible to count these cycles as discrete transients similar to the transients counted as listed in LRA Table 4.3-1. When reanalyzing the FW nozzle to account for the effects of the reactor water environment as part of the Fatigue Monitoring Program, the rapid FW cycling transient will be considered for the additional 20 years, as appropriate.

(c) In the GE stress report for the nozzle modifications, fatigue evaluation for planned operation thermal cycles was separated into on/off cycles and rapid (mixing) cycles. FW on/off cycling is starting and stopping FW flow to the reactor vessel associated with operation at low power and during startups and shutdowns. Rapid cycling is caused by intermittent leakage around the thermal sleeve (a press fit) and results in alternating temperatures on the blend radius of the FW nozzle to the vessel shell.

A TLAA as defined in 10 CFR 54.3 is an existing current licensing basis (CLB) analysis. The fatigue TLAA for license renewal and the CLB fatigue analysis are one and the same and, therefore, have the same basis. In the case of the FW nozzle, the CNS TLAA includes the effects of both on/off cycles and rapid cycling. The result of the screening analysis shown in LRA Table 4.3-3 was an environmentally adjusted CUF greater than 1.0 indicating the need for a refined analysis that will be applied through the Fatigue Monitoring Program prior to the end of the 40-year license term. Managing the effects of aging due to fatigue is in accordance with 10 CFR 54.21(c)(1)(iii).

The major transients analyzed for the reactor vessel are listed in USAR Table III-3-1, and Technical Specification 5.5.5 requires counting of reactor vessel design cycles. Because these design cycles represented all the significant thermal transients (normal and upset) that the designers could foresee, analysis of these transients satisfied the ASME III fatigue requirements for the reactor vessel.

NRC Request: *RAI 4.3.1-6*

Background:

LRA Section 4.3.1.3 discusses TLAA for Reactor Vessel Internals, in which it states, "A qualitative review of the internals was performed for the measurement uncertainty recapture, concluding that the governing stresses for all RPV internal components in the MUR condition remain bounded by the existing values".

Issue:

It is unclear how a qualitative review could produce creditable results to conclude that all RPV internal components in the MUR condition remain bounded by the existing values.

Request:

(a) *Provide basis to justify that a qualitative review is sufficient to conclude that all RPV internal components in the MUR condition remain bounded by the existing values.*

(b) *LRA Table 4.3-2 contains the CUF results for the RV internals. However, only a single location in the RV internal is reported, Core plate plugs. Why only one single location is reported? Is this the result from the original stress and fatigue analyses, or the value is reflecting the qualitative review and the value has accounted the MUR condition?*

(c) *Note 3 under Table 4.3-2 states that "Core plate plug CUF is for 32 EFPY and must be recalculated, or the plugs replaced, prior to the period of extended operation". This statement is translated to a commitment. Please confirm and include it in the Commitment list since it does not seem such an item existing in the current commitment list.*

NPPD Response:

(a) CNS previously submitted the license amendment request for the MUR power uprate to the NRC for review. (NPPD Letter NLS2007069, Stewart B. Minahan to U.S. NRC Document Control Desk, "License Amendment Request to Revise Technical Specifications - Appendix K Measurement Uncertainty Recapture Power Uprate," November 19, 2007) This submittal included a qualitative review of the reactor vessel internals fatigue. A qualitative review was considered adequate because the reactor vessel internals are not ASME code parts (non-pressure boundary parts). As such, no formal fatigue analysis is required and no formal fatigue analysis was performed as part of the current licensing basis. A qualitative review of reactor vessel internals fatigue is typical of what is done by GE and approved by the NRC for other power uprates. The NRC approved the Cooper MUR uprate via NRC letter, Carl F. Lyon to Stewart B. Minahan, "Cooper Nuclear Station - Issuance of Amendment Re: Measurement Uncertainty Recapture Power Uprate (TAC No. MD7385)", June 30, 2008. Section 3.5.2.2.2 of the Safety Evaluation states: "The NRC staff concurs with the licensee's assessment that the reactor internals are acceptable for operation at the uprated power level."

(b) There is no original stress and fatigue analysis for the reactor vessel internals as discussed in response to part (a). The CUF identified in LRA Table 4.3-2 (core plate plugs) was calculated as part of a modification that installed these plugs.

(c) Replacement of the core plate plugs is included in LRA commitment NLS2008071-04 for enhancement of the BWRVIP. That commitment reads as follows:

"Enhance the BWR Vessel Internals Program to include actions to replace the plugs in the core plate bypass holes based on their qualified life."

NRC Request: *RAI 4.3.1-7*

The NRC communicated that a revision to this RAI would be sent in a future letter. No NPPD response is required at this time.

NRC Request: *RAI B.1.1.1*

Background:

LRA Appendix B.1 Aging Management Programs and Activities, Section B.1.1 Aboveground Steel Tanks, states that the Aboveground Steel Tanks Program will be consistent with the program described in NUREG-1801, Generic Aging Lessons Learned (GALL) Report, Section XI.M29. Appendix A.1, "Aging Management Review– Generic," Table A.1-1, "Elements of an Aging Management Program for License Renewal."Report, identifies the ten elements of an acceptable AMP.

Issue:

LRA Section B1.1 commits to consistency with the Gall Report which includes the AMP ten elements. The CNS Aging Management Program Evaluation Report Non-Class 1 Mechanical, CNS-RPT-07-LRD07, Revision 2, Section 3.1 quotes the GALL Report XI.M29 element writeup and compares the CNS AMP to that. Description of the CNS AMP elements is not provided to evaluate the acceptability of the AMP.

Request:

For AMP B1.1, provide additional description of the basis, actions, support and specifics for the following elements:

A. *Scope of Program*
   1. *Since the fire water storage tanks' external painted surfaces are covered with insulation, clarify how periodic system walkdowns are adequate to manage the effects of corrosion and identify damaged coatings.*
   2. *The AMP states that paint was applied to the external surface of the tanks upon initial installation. Identify the current condition of the external paint and the basis for that determination.*

B. *Parameters Monitored or Inspected*
   1. *Since the fire water storage tanks' external painted surfaces are covered with insulation, clarify how periodic system walkdowns are adequate to manage the effects of corrosion and identify damaged coatings.*
   2. *Identify if tank side and bottom wall thickness will be periodically monitored or inspected.*
   3. *The AMP states that sealant was applied to the interface edge between the tank and concreter foundation upon installation. Identify the current condition of the sealant and the basis for that determination.*

C. *Detection of Aging Effects*
   1. *Since the fire water storage tanks' external painted surfaces are covered with insulation, clarify how periodic system walkdowns are adequate to manage the effects of corrosion and identify damaged coatings.*
   2. *Clarify how, and the frequency of, internal inspection or monitoring will adequately detect external corrosion, including at the steel/concrete interface.*
   3. *Provide basis for loss of material conditions and not measuring tank bottom surfaces prior due extended operation, and measuring thickness during the first ten years of extended operation.*

D. *Monitoring and Trending*
   1. *Since the fire water storage tanks' external painted surfaces are covered with insulation, clarify how periodic system walkdowns are adequate to manage the effects of corrosion and identify damaged coatings.*

E. *Acceptance Criteria*
   1. *Clarify t hat any degradation of the fire water storage tanks external surface pain and sealant at the steel/concrete interface will be an acceptance criteria, will be reported and will require further evaluation, or justify other criteria.*

<u>NPPD Response</u>:

As stated in LRA Section B.1.1, the new Aboveground Steel Tanks Program is consistent with the program described in NUREG-1801, Section XI.M29, Aboveground Steel Tanks. This GALL program is focused on potential loss of material at inaccessible locations where water can accumulate, such as the exterior of the tank bottom surface.

<u>Requests A.1, B.1, C.1, D.1</u>
Outdoor aboveground tanks are typically insulated, and the GALL program indirectly takes this into account when crediting periodic system walkdowns as part of the "detection of aging effects" element of the program. Periodic system walkdowns are performed as part of the External Surfaces Monitoring Program XI.M36. As described in XI.M36 scope section, insulated surfaces are inspected when the external surface is exposed (i.e., maintenance) at such intervals that would provide reasonable assurance that the effects of aging will be managed such that applicable components will perform their intended function during the PEO. Insulation

protects the external surface of the tank from exposure to the elements. Insulation degradation would be visible and indicate a potential pathway for precipitation to reach the painted surface of the tank. Excessive corrosion of tank surfaces under insulation will also result in discoloration outside of or external to the insulation lagging. Identification of staining on thermal insulation is an indicator of possible underlying degradation of the tank surface.

Request A.2
The most recent external and internal inspections of the tanks in September 2007 found no signs of corrosion of tank surfaces. The exterior insulation was found to have no discoloration, visible degradation, or staining that would indicate degradation of the external paint or provide a pathway for moisture to reach the tank surface.

Requests B.2, C.3
CNS has no operating experience indicating a loss of material from the bottom surfaces of the fire water storage tanks. Nevertheless, loss of material is conservatively identified as an aging effect requiring management for the tank bottom surfaces. CNS takes no exceptions to the program described in NUREG-1801, Section XI.M29; therefore, the CNS program provides for periodic thickness measurement of the tank bottoms to ensure that significant degradation is not occurring and the component intended function will be maintained during the PEO. The external surface of the tank walls are monitored through visual inspections as described in the response to A.1 above. The internal surface of the tank walls is managed by the Fire Water System Program, LRA Section B.1.17, which performs periodic inspections including wall thickness measurements of components included in the program.

Request B.3
As described in NUREG-1801, Section XI.M29, this sealant is a preventive measure to mitigate corrosion of the bottom surface of the tank by preventing water and moisture from penetrating the interface. The fire water storage tanks are insulated precluding ready access for inspection of the interface between the tank and concrete foundation. However, the CNS Aboveground Steel Tanks Program is a new program that, when implemented, will require inspection of this area. In accordance with NUREG-1801, Section XI.M29, and the CNS program acceptance criteria, degradation of the sealant that does not meet the acceptance criteria will require reporting and further evaluation under the site corrective action program.

Request C.2
Internal inspections and monitoring are not performed by this program for detection of corrosion on the external surface of the fire water storage tank walls. In accordance with NUREG-1801, Section XI.M29, loss of material from the tank wall exteriors is detected through external inspection as described in the response to A.1 above. Loss of material from the tank bottom exterior at the steel/concrete interface is detected using thickness measurements. The thickness measurements will be performed at least once during the first ten years of the PEO and

periodically thereafter. The results of the initial inspection will be used to determine the frequency of subsequent inspections.

Request E.1
The CNS Aboveground Steel Tanks Program requires that, as specified in NUREG-1801, Section XI.M29, any degradation of the fire water storage tanks external surface paint or sealant at the steel/concrete interface will be reported and will require further evaluation through the CNS corrective action program.

NRC Request: *RAI B.1.2-1*

Background:

In the CNS LRA, the B.1.2 "Bolting Integrity Program" states that it follows the guidance contained in NUREG-1339, EPRI NP-5769, and EPRI TR-104213. These guidance documents are referenced by the GALL XI.M18 Bolting Integrity Program. However, CNS states in their program basis documents that it also follows the guidance contained in other industry based recommendations including EPRI NP-5067, which is not referenced in the GALL Report.

Issue:

The use of references not explicitly identified in the GALL Report is considered an exception, and should be stated as such. Additionally, it is not clear when this guidance is used, and whether or not its usage will contradict the GALL guidance.

Request:

Please provide clarification on the use of EPRI NP-5067 as guidance for this program. Specifically, provide an explanation of any contradictions between the two sets of guidance and their impact on this program.

NPPD Response:

As stated in NUREG-1801 Section XI.M18, the staff's recommendations and guidelines for comprehensive bolting integrity programs that encompass all safety-related bolting are delineated in NUREG-1339. The industry's technical basis for the program for safety-related bolting and guidelines for material selection and testing, bolting preload control, ISI, plant operation and maintenance, and evaluation of the structural integrity of bolted joints, are outlined in EPRI NP-5769, with the exceptions noted in NUREG-1339. Section 8 of EPRI NP-5769 describes the two reference manuals developed by the Electric Power Research Institute (EPRI) for good bolting practices. These two manuals are also described in Section 2.2.2 of NUREG-1339 as part of the technical basis for resolution of the issue on bolting degradation or failure in nuclear power plants. These two manuals were subsequently published as EPRI NP-5067 "Good Bolting Practices Volume 1: Large Bolt Manual" and "Good Bolting Practices Volume 2: Small Bolt Manual." These well-known manuals are widely-used as reference material for the training of maintenance personnel throughout the United States. The guidance in these documents does not contradict information in EPRI NP-5769 nor NUREG-1339.

EPRI NP-5769 Section 8 points out that these two manuals are intended for maintenance personnel, not designers. LRA Section B.1.2 stipulates an enhancement to the Bolting Integrity Program at CNS to include design engineering guidance such as material selection, testing, and evaluation of the structural integrity of bolted joints from EPRI NP-5769 and EPRI TR-104213, which are specifically cited in NUREG-1801 Section XI.M18.

NRC Request: *RAI-B.1.2-2*

Background:

In the CNS LRA, the B.1.2 "Bolting Integrity Program" is not clear in how it satisfies the GALL Report program element "monitoring and trending". Specifically, the element recommends bolting connections for pressure retaining components (not covered by ASME Section XI) to be "inspected daily. If the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly".

Issue:

CNS credits their corrective action program for meeting this inspection frequency. However it was not readily apparent how this is achieved. If this recommendation is not specifically addressed in written procedures and guidance, then an exception will be needed.

Request:

Please provide detailed plans for inspection frequency which satisfy this GALL element or identify this as an exception, and provide the basis fur taking it as an exception.

NPPD Response:

The monitoring and trending element from the NUREG-1801 XI.M18 program description reads as follows:

> The inspection schedules of ASME Section XI are effective and ensure timely detection of applicable aging effects. If bolting connections for pressure retaining components (not covered by ASME Section XI) is reported to be leaking, then it may be inspected daily. If

the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly.

The term "may" is used throughout NUREG-1801 to indicate a possibility or permission, such as, granting permission to apply an alternative approach to a specific program action. NPPD took the same meaning for the term "may" in this program element. Consequently, the NPPD position does not constitute an exception to NUREG-1801. Nonetheless, the following justification is provided for the NPPD position on the frequency for monitoring leakage from pressure retaining components not covered by ASME Section XI. Components not covered by ASME Section XI are nonsafety-related components primarily found in auxiliary and steam and power conversion systems.

Leaks of bolting connections not covered by ASME Section XI are normally evaluated and corrective actions are specified using the CNS corrective action program. The corrective action program assigns a responsible organization and individual to perform a cause evaluation and determine any immediate corrective actions upon problem identification including monitoring.

In conjunction with the corrective action program, the CNS Fluid Leak Management Program specifies monitoring and trending to ensure that leaks which do not require immediately removing equipment from service for correction and do not challenge system or component functions are managed and corrected in a timely manner. Leak repair prioritization is determined through the work management process, in accordance with INPO AP-928, "Work Management Process Description," which prioritizes leak repairs based on operational significance.

The CNS Fluid Leak Management Program is based largely on guidance from "Establishing an Effective Fluid Leak Management Program, EPRI Sealing Technology and Plant Leakage Reduction Series (TR-114761)" and "Lube Oil System Leakage Mitigation, EPRI Sealing Technology and Plant Leakage Reduction Series (TR-111413)." Leaks are classified according to the source and the description. All plant leakage is tracked via work order number and monitored by system engineering. Daily rounds performed by operators also contribute to the monitoring of leaks.

The NRC Staff, as documented in Section 3.0.3.1.3 of the license renewal preliminary SER for Beaver Valley (ADAMS Accession Number ML090120360), has accepted the position that such an approach for leakage monitoring of non-ASME bolted connections demonstrates proper management of leakage through robust plant programs which meet the intent of the GALL Report "Monitoring and Trending" program element.

NRC Request: *RAI-B.1.2-3*

Background:

In the CNS LRA, the B.1.2 "Bolting Integrity Program" identifies an enhancement to the GALL report program element "preventive actions" regarding enhancement of guidance to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC, to clarify the prohibition on use of lubricants containing MoS_2 for bolting at CNS, and to specify that proper gasket compression will be visually verified following assembly.

Issue:

The CNS LRA is not clear whether or not guidance being updated as a result of the enhancements will be applied to existing components to verify their compliance with the enhancements.

Request:

Please provide clarification on how the guidance which will be updated as a result of the listed enhancements will be applied to existing components.

NPPD Response:

Appropriate actions with regard to material selection, bolting lubricants, and gasket compression were taken in accordance with the June 1990 resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants (NUREG-1339) which is one of the references for NUREG-1801, Section XI.M18 "Bolting Integrity." Site-specific operating experience indicates that the actions addressed by the listed enhancements have been effectively applied to existing components.

NRC Request: *RAI B.1.2-4*

Background:

In the CNS LRA, the B.1.2 "Bolting Integrity Program" is stated to be a stand alone program which manages all bolts within the scope of license renewal with the exception of the reactor head studs. Upon closer review of the LRA, the staff has identified 3 line items which manage bolting, that are credited to be managed by other programs- Buried Piping and Tanks Inspection, and the Periodic Surveillance and Preventive Maintenance Program.

Issue:

The GALL Bolting Integrity Program allows for supplementation by other AMPs. However, a review must be done to ensure that these supplemental programs carry out the aging management recommendations of the Bolting Integrity Program. Since the LRA appears to have contradictory information, it is not clear which AMP will be used to manage the components and how it will be done.

Request:

Please provide clarification on the 3 line items described above, as well as the Bolting Integrity Program in regards to the use of programs to supplement it.

NPPD Response:

The Bolting Integrity Program addresses multiple aging effects for bolting. The program includes periodic inspection of closure bolting for signs of leakage that may be due to crack initiation, loss of preload, or loss of material due to corrosion. The program also includes preventive measures to preclude or minimize loss of preload and cracking. As stated in LRA Appendix B, the program applies to bolting and torquing practices of all bolting regardless of size except reactor head closure studs. This does not preclude managing some aging effects for bolting by means of another program, if appropriate. For three line items in the LRA aging management results tables, loss of material is managed by a different program, but the Bolting Integrity Program still addresses other aging effects (e.g., loss of preload) for this bolting.

The three line items for bolting that credit a program in addition to the Bolting Integrity Program are the following:

- bolting on buried piping of the fuel oil systems,
- bolting on buried piping of the fire protection – water system and
- bolting on submerged piping of the plant drain systems.

The bolting in these line items is normally inaccessible, requiring a planned maintenance activity to expose the bolting for inspection. The inspection of the bolting to manage loss of material for these line items is part of the planned maintenance activity.

For the bolting on buried piping, the Buried Piping and Tanks Program governs when the bolting is exposed for inspection and also governs the inspection of buried components. Coatings and wrappings of buried components will be visually inspected for coating perforation or other damage. The integrity of the coatings and wrappings is sufficient to demonstrate no significant loss of material from the external surfaces of the components, including the bolting. If the coatings and wrappings are intact, the bolting would not be exposed for further inspection; thus, the Buried Piping and Tanks Program is credited for managing loss of material. However, if the bolting was exposed because of coating degradation or for other planned maintenance, the elements of the Bolting Integrity Program would be implemented to assure the intended function of the bolting is maintained when the piping system is returned to service.

Similarly, the bolting on the submerged piping of the plant drain systems would be exposed for inspection (e.g., by draining a sump), and would be inspected by the Periodic Surveillance and Preventive Maintenance (PSPM) Program. The program will require a visual inspection of components, including bolting, to assure no unacceptable loss of material; thus, the PSPM Program is credited for managing loss of material. If the bolting was exposed because of bolting degradation or for other planned maintenance, the elements of the Bolting Integrity Program would be implemented to assure the intended function of the bolting is maintained when the piping system is returned to service.

NRC Request: *RAI B.1.3-1*

Background:

The applicant states that the proposed aging management program (B.1.3) is consistent with the GALL Report. The scope of the proposed aging management program includes stainless steel. The scope of the Buried Piping Inspection Aging Management Program contained in the GALL Report includes "buried steel piping and tanks". According to chapter IX.C of Volume 2 of the GALL Report, the definition of steel includes carbon steel as well as several types of cast iron and low alloy steels. Stainless steel is specifically not included in the definition of steel.

Issue:

Unlike steel, stainless steel is an active passive metal which is normally in its passive state. While it is possible for stainless steel to maintain its corrosion resistance in a non oxidizing environment if it is not physically damaged, to ensure the corrosion resistance of stainless steel, it is preferable to use it only in an oxidizing environment.

The aging management program (B.1.3) as proposed, includes stainless steel piping and tanks. Aging management program B.1.3, as proposed, also requires all pipes be coated. It is possible that the coating of stainless steel could place it in a reducing environment or an environment in which anaerobic bacteria could be prevalent. This could result in poor corrosion performance of the stainless steel piping.

Request:

Please justify the inclusion of stainless steel in the proposed aging management program or propose a different program for buried stainless steel components.

NPPD Response:

As indicated in LRA Section 3.2, only one component type, restriction orifice (representing two separate components) in the standby gas treatment system, was composed of stainless steel and exposed to a soil environment. During preparation of the LRA, these components were conservatively assumed to be exposed to soil as part of a run of buried carbon steel piping. These restriction orifices have since been determined to be located at the end of the pipe run before it enters the ground. The orifices are therefore externally exposed to outdoor air rather than soil (Note - there is no comparable NUREG-1801 line item for this material/environment combination). Accordingly, LRA Sections 3.2.2.2.3, Table 3.2.1, Table 3.2.2-6, A.1.1.3, and B.1.3 have been revised to reflect this (see Attachment 2).

NRC Request: *RAI B.1.3-2*

Background:

The GALL Report recommends that the protective coatings applied to buried piping be in accordance with industry standard practice. The proposed aging management program states that protective coatings will be applied to buried piping but does not state that these coatings will be in accordance with industry standard practice.

Issue:

Based on the wording of the proposed aging management program (B.1.3) it would be possible to utilize a non standard coating and still comply with the proposed program. A non standard coating may, or may not, be effective in preventing corrosion of buried piping.

Request:

Please confirm that all piping coatings are in accordance with industry standard practice. Please identify the standard.

NPPD Response:

As stated in LRA Section B.1.3, the Buried Piping and Tanks Inspection program will use standard industry practice for external coatings and wrappings. Per site specifications, the material application of coating and coverings shall be in strict accordance with the latest issue of American Water Works Association Specification C203, Coal-Tar Protective Coatings and Linings for Steel Water Pipelines-Enamel and Tape-Hot-Applied. This industry specification was also used during the original installation of buried components at CNS.

NRC Request: *RAI B.1.6-1 (same as RAI B.1.8-1)*

Background:

The applicant stated that LRA AMP B.1.6 and B.1.8 are consistent with GALL AMP XI.M8 and AMP XI.M4, respectively. The GALL AMPs provide the same inspection guidelines for Inconel 182 welds and stainless steel welds. However, recent industry experience at Pilgrim Nuclear Station indicated that CRD return line cap weld (Inconel 182 weld) experienced through wall crack due to IGSCC.

Issue:

Since Inconel 182 welds are more susceptible to IGSCC when exposed to BWR RCS water than the stainless steel welds, the inspection criteria for the 182 welds is different from stainless steel welds.

Request:

Identify where Inconel 182 welds exposed to RCS water are used in the following systems: (1) BWR Attachment Welds; and (2) BWR Vessel Penetrations. How this aging effect is managed?

NPPD Response:

The majority of the CNS reactor vessel internal attachment welds were fabricated with Inconel 182 filler with a lesser share fabricated with stainless steel (E308) filler. Cracking of the vessel internal attachment welds is managed by the Water Chemistry Control – BWR Program and the BWR Vessel ID Attachment Welds Program, which includes visual test (VT) examinations in accordance with BWRVIP-48-A. CNS also performs visual inspections per the requirements of ASME Section XI, Item B13.20 (VT-1 of welds in beltline), B13.30 (VT-3 of welds outside of beltline), and B13.40 (VT-3 of surfaces defined as core support structures).

Inconel 182 welds are exposed to RCS water in six instrument line nozzle to safe-end welds at the N11A/B, N12A/B, and N16A/B nozzle locations. Cracking of the instrument penetration nozzles and welds is managed by the Water Chemistry Control – BWR Program, which is consistent with BWRVIP-130 (which superseded BWRVIP-29), and the BWR Penetrations Program. Inspections of these instrument penetration nozzles are in accordance with ASME, Section XI and BWRVIP-49-A which requires a VT-2 examination every outage. N12A/B are exempt from volumetric inspection per IWB-1220. Per the CNS risk-informed ISI (RI-ISI) Program, N11A/B are not selected for (but are subject to) volumetric inspection. N16A/B are volumetrically examined every 10 years in accordance with the CNS RI-ISI Program.

Inconel 182 is also exposed to RCS water in the CRD return line cap weld at the N9 nozzle. Cracking of the CRD return line cap weld is managed by the Water Chemistry Control – BWR Program and the BWR Stress Corrosion Cracking Program. The CRD return line cap weld is examined every six years in accordance with BWRVIP-75-A.

NRC Request: *RAI B.1.7-1*

Background:

In LRA Tables 3.1.1, item 3.1.1-41, the applicant states that for some components of the Reactor Coolant System (RCS), to which the BWR Stress Corrosion Cracking (SCC) AMP is not applicable, SCC is managed by the Water Chemistry Control – BWR Program and either the Inservice Inspection – ISI or One-Time Inspection Program is used.

Issue:

It is not clear what components of the RCS do not credit the BWR SCC AMP.

Request:

Clarify what components of the RCS do not credit the BWR SCC AMP. Provide the justification to use a different aging management program for the components rather than the BWR SCC AMP.

NPPD Response:

The discussion column of Table 3.1.1, item 3.1.1-41, summarizes the results presented in Tables 3.1.2-1, 3.1.2-2 and 3.1.2-3, that are compared to NUREG-1801 Volume 2 Items IV.A1-1 and IV.C1-9.

Seven lines in Table 3.1.2-1 are compared to item IV.A1-1, but credit the Inservice Inspection - ISI program instead of the BWR Stress Corrosion Cracking (SCC) Program. Note E, indicating that a different program from that recommended by NUREG-1801, was used for each of these lines. These lines represent low alloy steel nozzles and shell components clad with stainless steel. The stainless steel cladding is exposed to reactor coolant (treated water >140°F) and is susceptible to stress corrosion cracking. NUREG-1801 does not explicitly address this material, or environment and aging effect combination for these components, so the comparison to item IV.A1-1, for nozzle safe ends and welds, was selected as a reasonable alternative. The BWR SCC Program applies primarily to stainless steel piping and welds. The program does not apply to stainless cladding of steel shell and nozzle components. The use of the Inservice Inspection - ISI program in lieu of the BWR SCC Program is considered an effective means of detecting and managing cracking in these components.

Similarly, two lines in Table 3.1.2-3 are compared to item IV.C1-9, but credit the Inservice Inspection - ISI or One-Time Inspection Program instead of the BWR SCC Program. Note E, indicating that a different program from that recommended by NUREG-1801, was used for each of these lines. These lines represent the CRDs and the flow elements within the main steam piping. The stainless steel CRDs and cast austenitic stainless steel (CASS) flow elements are exposed to reactor coolant (treated water >140°F) and are susceptible to stress corrosion cracking. NUREG-1801 does not explicitly address this material (or environment and aging effect combination for these components) so the comparison to item IV.C1-9 for piping elements greater than or equal to 4 NPS was selected as a reasonable alternative. The Inservice Inspection - ISI Program is considered an effective means of detecting cracking in the CRDs. For the flow elements, which are not part of the pressure boundary, the One-Time Inspection Program is considered an effective means to demonstrate that cracking is not a significant aging effect.

NRC Request: *RAI B.1.7-2*

Background:

In LRA Tables 3.2.2-2 and 3.2.2-8-2, the Core Spray System AMR items do not include any AMR item to manage stainless steel stress corrosion cracking (SCC) of piping in a treated water (> 140 °F) environment. The GALL Report recommends the BWR Stress Corrosion Cracking Program to manage SCC in the Engineered Safety Features System including the Core Spray System.

Issue:

It is not clear whether an adequate AMP is credited for SCC in the Core Spray System.

Request:

Provide what AMP and AMR items are used to manage SCC in the Core Spray System if the system has the components subject to SCC.

NPPD Response:

Section 2.3.2.2 of the LRA describes the core spray system. As stated within that section, Class 1 components of the system are reviewed as part of the reactor coolant pressure boundary (Section 2.3.1.3). The portions of the core spray system exposed to temperatures greater than 140°F are within the Class 1 reactor coolant pressure boundary. Aging management review results for these components appear in Table 3.1.2-3.

LRA Tables 3.2.2-2 and 3.2.2-8-2 present the aging management review results for non-Class 1 core spray system components. Components in this portion of the system are not exposed to temperatures greater than 140°F. Consequently, these components are not subject to stress corrosion cracking.

NRC Request: *RAI B.1.7-3*

Background:

In the LRA, the applicant describes the AMR items of stainless steel piping in the Engineered Safety Features (ESF) System such as RHR, HPCI and RCIC Systems that are subject to stress corrosion cracking in a treated water (> 140 °F) environment. The consistency note for the AMR items is Note E, which means that the material, environment, and aging effect are consistent with the GALL Report, but a different aging management is credited rather than the BWR SCC program.

In the LRA, the applicant also describes the AMR items for stainless steel piping in the Auxiliary System that are subject to stress corrosion cracking in a treated water (> 140 °F) environment. The consistency note for the AMR items is also Note E as its implication is described above. In contrast to the Note E, LRA Table 3.2.1, item 3.2.1-18 and Table 3.3.1, item 3.3.1-38 indicate that none of the Engineered Safety Features System or Auxiliary System components are within the scope of the BWR Stress Corrosion Cracking Program and all relevant components are included in the reactor vessel, internals and reactor coolant system.

Issue:

It is not clear whether SCC in all components of the ESF and Auxiliary Systems is managed by an adequate aging management program.

Request:

Clarify what portions of the ESF and Auxiliary Systems are managed by the BWR SCC Program. Provide what aging management program is used to manage SCC in the other portions of the ESF and Auxiliary Systems if a different aging management program is used rather than the BWR SCC program.

NPPD Response:

For systems that operate intermittently, the license renewal aging management review process conservatively selects the limiting environment for determination of aging effects. For example, portions of the residual heat removal (RHR) system, which is in standby at ambient temperature during normal operation, will be exposed to temperatures >140°F when the system operates during shutdowns; so treated water >140°F is the environment evaluated. Parts of the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems, which are also in standby and only operate during testing, are similarly evaluated assuming a treated water > 140 °F environment. Stainless steel components exposed to treated water > 140 °F are subject to stress corrosion cracking.

The Water Chemistry Control – BWR Program, along with the One-Time Inspection Program to verify the chemistry program effectiveness, manages stress corrosion cracking for these Engineered Safety Features (ESF) and auxiliary systems components. This is consistent with other NUREG-1801 items (e.g., VIII.E-31).

These aging management review results were compared to NUREG-1801 lines in the ESF and auxiliary systems tables that include the BWR SCC Program since they provided the best possible match. Note E was applied to these items because the BWR SCC Program does not apply to these components.

As stated in NUREG-1801, the BWR SCC Program includes all BWR austenitic stainless steel piping that is 4 inches or larger in nominal diameter and that contains reactor coolant at a temperature above 200 °F during power operation regardless of ASME Code classification. Since most RHR, HPCI and RCIC components are normally in standby at ambient temperatures (< 200 °F) during power operation, they are not included in the program. The portions of the ESF and auxiliary systems exposed to reactor coolant at temperatures greater than 200 °F during power operation are Class 1 components evaluated as part of the reactor coolant pressure boundary. Aging management review results for these components appear in Table 3.1.2-3.

NRC Request: *RAI B.1.7.4*

Background

The staff found that the ASME Code Section XI, 2001 Edition, 2003 Addenda was used for the program elements, Acceptance Criteria and Corrective Actions, of the applicant's program rather than the ASME Code Section XI, 1986 Edition as recommended by the GALL Report.

Issue

The edition and addenda of the ASME Code Section XI that the applicant program uses in the program are different from those the GALL Report recommends.

Request

Provide the justification for the program's use of a different edition and addenda of the ASME Code Section XI for the program elements.

NPPD Response:

The NUREG-1801, XI.M7, BWR SCC program description identifies sections of the ASME Code in two of the 10 program elements, one of which specifies a particular edition of the Code. The NUREG-1801, XI.M7 Acceptance Criteria program element recommendation of the 1986 Code edition is based on the original issue of GL 88-01, January 25, 1988 (Note- GL 88-01, Supplement 1, February 1992, does not mention any specific code edition) and NUREG-0313, Revision 2. The NUREG-1801, XI.M7 Acceptance Criteria recommendation specifically applies to flaw evaluations in accordance with ASME Section XI, IWB-3600. This is consistent with both GL 88-01 and NUREG-0313 which mentioned the 1986 Code edition only in reference to flaw evaluations in accordance with IWB-3600.

The following excerpt is from NUREG-0313, Revision 2, Section 4.1, which established the basis for using the 1986 Code edition rather than earlier versions:

"In IWB 3641, the Code (Winter 83 Addenda) provided simple tables of allowable crack depth as a function of the primary stress level and crack length... It was recognized that these tables did not provide an acceptable level of margin against failure for low toughness materials such as fluxed welds (SAW, SMAW)... This problem has now been addressed by the Code, and the 1986 Edition provides appropriate criteria for all types of welds."

In 1988, when both GL 88-01 and NUREG-0313, Rev.2 were issued, the use of earlier code editions (e.g., Winter 83 Addenda) would have been common in the industry. The limitation to use the 1986 edition of IWB-3600 was appropriate at the time. This issue is addressed in 10 CFR 50.55a(b)(2)(v) as a limitation on the application of the Winter 1983 Addenda and Winter 1984 Addenda.

The correction provided in the 1986 edition has been maintained (although in different forms since the 1996 Addenda) in subsequent editions of the Code. The limitation in 10 CFR 50.55a(b)(2)(v) does not appear for any subsequent edition or addenda. Consequently, the use of the ASME Code Section XI, 2001 Edition, 2003 Addenda for flaw evaluations is consistent with the requirements of GL 88-01, NUREG-0313, and NUREG-1801, XI.M7.

The NUREG-1801, XI.M7 Corrective Action program element does not specify and is not dependent on any particular edition of the Code. To the extent flaw evaluation criteria are used to evaluate the acceptability of crack overlay weldments, GL 88-01 does reference the 1986 edition of IWB-3600 for the reasons stated above. However, neither NUREG-0313 nor GL 88-01 establishes any edition limitations on the other code sections listed in the NUREG-1801, XI.M7 Corrective Action program element (ASME Section XI, Subsections IWB-4000 and IWB-7000, IWC-4000 and IWC-7000, or IWD-4000 and IWD-7000 and Code Case N-504-1).

Since the NUREG-1801, XI.M7 Corrective Action program element specifies no edition of the Code, the use of ASME Code Section XI, 2001 Edition, 2003 Addenda is acceptable.

NRC Request: *RAI B.1.8-1 (same as RAI B.1.6.1)*

Background

The applicant stated that LRA AMP B.1.6 and B.1.8 are consistent with GALL AMP XI.M8 and AMP XI.M4, respectively. The GALL AMPs provide the same inspection guidelines for Inconel 182 welds and stainless steel welds. However, recent industry experience at Pilgrim Nuclear Station indicated that CRD return line cap weld (Inconel 182 weld) experienced through wall crack due to IGSCC.

Issue

Since Inconel 182 welds are more susceptible to IGSCC when exposed to BWR RCS water than the stainless steel welds, the inspection criteria for the 182 welds is different from stainless steel welds.

Request

Identify where Inconel 182 welds exposed to RCS water are used in the following systems: (1) BWR Attachment Welds; and (2) BWR Vessel Penetrations. How this aging effect is managed?

NPPD Response:

The majority of the CNS reactor vessel internal attachment welds were fabricated with Inconel 182 filler with a lesser share fabricated with stainless steel (E308) filler. Cracking of the vessel internal attachment welds is managed by the Water Chemistry Control – BWR Program and the BWR Vessel ID Attachment Welds Program, which includes VT examinations in accordance with BWRVIP-48-A. CNS also performs visual inspections per the requirements of ASME Section XI, Item B13.20 (VT-1 of welds in beltline), B13.30 (VT-3 of welds outside of beltline), and B13.40 (VT-3 of surfaces defined as core support structures).

Inconel 182 welds are exposed to RCS water in six instrument line nozzle to safe-end welds at the N11A/B, N12A/B, and N16A/B nozzle locations. Cracking of the instrument penetration nozzles and welds is managed by the Water Chemistry Control – BWR Program, which is consistent with BWRVIP-130 (which superseded BWRVIP-29), and the BWR Penetrations Program. Inspections of these instrument penetration nozzles are in accordance with ASME, Section XI and BWRVIP-49-A which requires a VT-2 examination every outage. N12A/B are exempt from volumetric inspection per IWB-1220. Per the CNS RI-ISI Program, N11A/B are not selected for (but subject to) volumetric inspection. N16A/B are volumetrically examined every 10 years in accordance with the CNS RI-ISI Program.

Inconel 182 is also exposed to RCS water in the CRD return line cap weld at the N9 nozzle. Cracking of the CRD return line cap weld is managed by the Water Chemistry Control – BWR Program and the BWR Stress Corrosion Cracking Program. The CRD return line cap weld is examined every six years in accordance with BWRVIP-75-A.

NRC Request: *RAI B.1.9-1*

Background:

LRA AMP B.1.9, "BWR Vessel Internals," manages the aging degradation of various reactor vessel internals (RVI) components. Top guide grid beams are one of the RVI components that are susceptible to irradiated stress corrosion cracking (IASCC) when exposed to a neutron fluence value greater than 5×10^{21} (E > 1 MeV). Table IV B1-17 in NUREG 1801, Revision 1, "Generic Aging Lessons Learned (GALL) Report," states that 5 percent of these top guide locations that are exposed to a fluence value greater than the aforementioned threshold value will be inspected using EVT-1 within six years after entering the period of extended operation. An additional 5 percent of these top guide locations will be inspected within 12 years after entering the period of extended operation.

Issue:

Contrary to this guidance in GALL, the applicant, in Appendix C, "Response to BWRVIP Applicant Action Items Cooper Nuclear Station," of the LRA stated that it will comply with the inspection requirements specified in the BWRVIP-26 report which does not include the GALL's inspection guidelines for the top guide components.

Request:

Clarify the inspection approach, method, frequency, and acceptance criteria that will be implemented.

NPPD Response:

As stated in LRA Appendix B, Section B.1.9, the BWRVIP, with enhancements, is consistent with the program described in NUREG-1801, Section XI.M9, BWR Vessel Internals. Top guide inspections will therefore be performed in accordance with BWRVIP-183, which provides the same top guide inspection guidance presented in NUREG-1801 Section XI.M9.

The purpose of LRA Appendix C is to demonstrate compliance with the license renewal applicant action items identified in the safety evaluations for applicable BWRVIP documents. The statement that CNS has implemented the inspection requirements of BWRVIP-26-A is intended to support the demonstration of compliance, and does not contradict information presented in Appendix B of the LRA.

NRC Request: *RAI B.1.9-2*

Background:

Reduction in ductility and fracture toughness can occur in stainless steel RVI components when they are exposed to high-energy neutrons (E > 1 MeV). In August 2006, the BWRVIP issued a staff-approved BWRVIP-100-A report, "Updated Assessment of the Fracture Toughness of Irradiated Stainless Steel for BWR Core Shrouds," which discusses fracture toughness results for the irradiated stainless steel materials. For stainless steel materials with exposure to a neutron fluence value equal to or greater than 1 X 10^{21} n/cm^2 (E > 1 MeV), the BWRVIP-100-A report identified lower fracture toughness value than that of the value reported in Appendix C of the BWRVIP-76 report, "BWR Vessel and Internals Project BWR Core Shroud Inspection and Flaw Evaluation Guidelines." During the license renewal period, core shroud welds and base materials may be exposed to neutron fluence values 1 X 10^{21} n/cm^2 (E > 1 MeV) or greater. The GALL AMP XI.M9 recommends that the flaw evaluation guidelines of the BWRVIP-76 shall be applied for cracked core shroud components.

Issue:

Since the inspection -100-A report, the staff is concerned that less conservative fracture toughness values could be used in the BWRVIP-76 report is based on fracture toughness values which are less conservative than the BWRVIP in the flaw evaluation methodology.

Request:

The staff requests that the applicant make a commitment that it will incorporate the crack growth rate evaluations specified in the BWRVIP-100-A report and develop generic inspection intervals for core shroud welds that are exposed to a neutron fluence value equal to or greater than 1 X 10^{21} n/cm^2. Provide the basis for using the non-conservative fracture toughness values of BWRVIP-76 instead of the values identified in BWRVIP-100-A report.

NPPD Response:

NPPD is committed to the BWRVIP at CNS. This commitment requires the timely implementation of new or revised guidelines as they are issued. BWRVIP-100-A has been incorporated into the CNS Vessel Internals Program.

NPPD already applies the more conservative fracture toughness values documented in BWRVIP-100-A for the fracture mechanics evaluation of shroud inspection results for CNS. The results of the latest evaluation are the basis used to establish the shroud re-inspection interval of 10 years.

NRC Request: *RAI B.1.9-3*

Background:

The GALL AMR line item IV B1-14 indicates that cumulative fatigue evaluation is a TLAA for core shroud components.

Issue:

In section 5.5 of the applicant's report CR-CNS-07-LRD04, "CNS Licensing Renewal Project – TLAA-Mechanical Fatigue," the applicant stated that the fatigue evaluation of the core shroud components is not based on the life of the plant and, therefore, it is not a TLAA.

Request:

Describe the details of any fatigue/cyclic or crack growth analysis that was performed for the core shroud. Also, please identify whether that analysis is a TLAA and demonstrate how the requirements of 10 CFR 54.21(c)(1) are met.

NPPD Response:

The shroud support is manufactured and analyzed as part of the reactor vessel by the manufacturer. The shroud support is an ASME code component and the cumulative usage factors for the 1) shroud support plate to vessel shell junction, 2) shroud support gusset to vessel junction and 3) shroud and shroud support cylinder are given in LRA Table 4.3-2. These fatigue analyses are TLAAs based on the numbers of design transients. The effect of fatigue on the shroud support is being managed by the Fatigue Monitoring Program for the PEO in accordance with 10 CFR 54.21(c)(1)(iii).

The core shroud is not an ASME code component (it is not part of the pressure boundary). No fatigue analyses were performed as part of the original design of the shroud. CNS identified indications in multiple shroud welds in January 2005 and re-inspected the indications in November 2006. These are not ASME code welds and are not evaluated per the code. The welds were inspected based on BWRVIP guidelines and were evaluated according to BWRVIP-76, including plant-specific evaluations per BWRVIP-94. The evaluation showed the shroud to be acceptable without additional inspections for at least 10 years. Follow-up inspections are planned in accordance with the evaluation. This evaluation does not involve time-limited assumptions defined by the current operating term (40 years) and therefore is not a TLAA.

NRC Request: *RAI B.1.10-1*

Background:

As documented in LR-ISG-2006-01, past operating experience in Mark I steel containments has shown that loss of material due to corrosion may be significant in inaccessible sand bed regions. During our discussions, the applicant informed us that they performed a drywell sand cushion drain vacuum test in 1993 to address this issue.

Issue:

In looking at the results of the vacuum test, the staff found that only four of the eight sand cushion drains were tested to verify the areas were free of water. Although these tests did not reveal moisture, this does not ensure that the sand bed region is free of moisture as the remaining four sand drains were not tested. In addition, since the test was completed more than 15 years ago, there is no reasonable assurance that the results from the test are still valid.

Request:

Explain how CNS will verify that the remaining four (4) sand cushion drains are obstruction free. Furthermore, how CNS ensures there is no leakage causing moisture in the sand bed region, which could lead to corrosion of the drywell shell during the period of extended operation.

NPPD Response:

The CNS drywell sand bed region is equipped with eight drain lines to avoid collecting water or moisture in the region in case of a leak during refueling evolutions when the reactor cavity is filled. A vacuum test of four out of eight lines in 1993 verified that the drain lines are unplugged and are functioning properly. To ensure the lines are obstruction free, a vacuum test of all eight sand bed drain lines will be performed prior to the period of extended operation.

The potential source of moisture which could enter the sand bed region is refueling water after the refueling cavity is filled during refueling outages. To ensure the drywell shell exterior and sand bed region remain dry during refueling evolutions, the drywell to reactor building bellows assembly separates the refueling cavity filled with water from the exterior surface of the drywell shell. Potential leakage from the bellows assembly or the refueling cavity is removed through drain lines, eliminating the risk of water entering the sand bed region. The reactor well drains are welded and do not contain seals or gaskets, which reduces the risk of leakage. If leakage does pass through the reactor building bellows assembly or the reactor cavity liner, during refueling activities, a flow indicating switch alarms to alert operations. This flow indicating switch, set to alarm at 5 gpm, is observed once per shift by station operators when the reactor cavity is flooded. This switch is calibrated yearly to verify its functionality. A review of the calibration results of this switch for the past eight years did not indicate any instance where the switch was out of order. The CNS drywell sand bed region drain lines are also inspected during the refueling outages while the refueling cavity is filled for any signs of leakage.

Operating experience reviewed at CNS found no occurrences of leakage into the annulus air gap. In addition, no leakage has been found through the refueling bellows into the area monitored by the air gap leakage detection system.

NRC Request: *RAI B.1.12-1*

Background:

LRA Section B.1.12 states that the Acceptance Criteria program element will be enhanced to specify the acceptance criterion for UT thickness measurements of the bottom surfaces of the diesel fuel oil day tanks, the diesel fuel oil storage tanks, and the diesel fire pump fuel oil storage tank.

Issue:

The LRA did not provide information pertaining to how the acceptance criteria for the UT thickness measurements of the bottom surfaces will be established.

Request:

Please clarify how the acceptance criteria for the UT thickness measurements of the bottom surfaces will be established and what this criteria will be based on.

NPPD Response:

The acceptance criteria for UT measurement of tank bottom thickness for the referenced diesel fuel tanks will be based on component as-built information adjusted for corrosion allowance. If measurements show less than the minimum nominal thickness less corrosion allowance, engineering will evaluate the measured thickness for acceptability under the corrective action program. Evaluation will include consideration of potential future corrosion to ensure that future inspections are scheduled before wall thickness becomes unacceptable.

<u>NRC Request</u>: *RAI B.1.12-2*

<u>Background:</u>

LRA Section B.1.12 states that sampling of fuel oil in diesel oil storage tank B showed indications of excessive water in the tank in 2005. The applicant stated that corrective actions were taken which included dewatering the diesel storage tank B so it was within acceptable limits. Later, in 2005 and 2006, samples of fuel oil were taken from the same tank and showed water. Further evaluation of these results indicated that the water was within acceptable limits. The applicant revised its testing procedures in order to clarify testing methods.

<u>Issue:</u>

The LRA did not provide information on the cause of the excessive water in the diesel oil storage tank B. Also, the LRA did not specify if any inspections were performed on the tank to see if the water had degraded the interior of the diesel storage tank B.

<u>Request:</u>

(a) *Clarify the cause of the water in the diesel fuel that was discovered in the diesel oil storage tank B for the later time periods and provide details on the steps taken to correct these deficiencies to prevent recurrence in the future.*

(b) *Clarify if any inspections were performed to verify the condition of the tank interior and confirm that degradation has not occurred and provide a summary of the results.*

(c) *Provide a summary of results from subsequent sampling results of the fuel oil and any corrective actions that were taken based on these results.*

<u>NPPD Response</u>:

(a) The apparent cause of water found in diesel oil storage tank 'B' was water from a "contingency" diesel fuel oil tanker mobilized in May 2004. The "contingency" tanker was an interim measure to strengthen CNS capability to supply fuel to the emergency diesel generators during fuel oil storage tank and transfer system maintenance. Diesel fuel oil contaminated with water was off-loaded from this tanker into diesel oil storage tank 'B' in September 2005. The water was removed from diesel oil storage tank 'B' with a pump and a bottom (thief) sampler. The thief sampler was used to remove the water to the "extent possible" as described in Technical Specification Bases SR 3.8.3.5. A small amount of water, estimated at 1.5 gallons, remained in diesel oil storage tank 'B'.

CNS uses a receipt inspection fuel oil tanker to temporarily store incoming diesel fuel oil until laboratory analyses are completed to demonstrate the incoming diesel fuel oil is acceptable for transfer into the permanent fuel oil storage tanks. The "contingency" diesel fuel oil tanker is no longer on-site. Corrective actions for the water intrusion event in 2005 included providing the receipt inspection fuel oil tanker compartment drain piping with a sample valve on each connection (four total) to facilitate periodic water sampling and water removal from the tanker drain piping. Revised procedures now require use of the new sample valves to identify and remove water prior to transfer from the receipt inspection fuel oil tanker into permanent fuel oil storage tanks 'A' and 'B'.

Bottom samples following the 2005 event found very small amounts of water in diesel oil storage tank 'B'. The small amounts of water were consistent with the amount of water that could not be recovered from diesel oil storage tank 'B' following the contamination event.

(b) In the fall of 2004, the diesel oil storage tanks were individually blast cleaned, ultrasonically inspected, and lined with an epoxy. No evidence of corrosion was identified during these inspections. The epoxy lining is designed to prevent any small amount of water in the tank from degrading the interior metal surface. Consequently, no inspections have been deemed necessary to evaluate the condition of the tank interior since the 2005 water contamination event. A subsequent bottom vacuum and high velocity recirculation was performed on the diesel oil storage tanks in March 2009 to remove bottom water and particulates, if any, from both diesel oil storage tanks. The next draining and visual inspection of the diesel oil storage tanks is scheduled for 2014, consistent with the 10-year inspection frequency of Regulatory Guide 1.137.

(c) A review of the monthly surveillance results for bottom sampling of the diesel oil storage tanks since the bottom vacuuming and recirculation activities in March 2009 identified no evidence of water remaining in diesel oil storage tank 'B'.

<u>NRC Request</u>: *RAI B.1.13-1*

<u>Background:</u>

NUREG-1801 for program element, "Acceptance Criteria" states:

Acceptance Criteria:
10 CFR 50.49 acceptance criteria are that an inservice EQ component is maintained within the bounds of its qualification basis, including (a) its established qualified life and (b) continued qualification for the projected accident conditions. 10 CFR 50.49 requires refurbishment, replacement, or requalification prior to exceeding the NUREG-1801, Rev. 1 X E-4 September

> *2005 qualified life of each installed device. When monitoring is used to modify a component qualified life, plant-specific acceptance criteria are established based on applicable 10 CFR 50.49(f) qualification methods.*

Issue:

Part (b) of the acceptance criteria, "continued qualification for the projected accident conditions," is not included in B.1.13, program element, "Acceptance Criteria."

Request:

Provide the justification for the missing acceptance criteria or revise to include the missing information under part (b).

NPPD Response:

CNS LRA Section B.1.13 for NUREG-1801 Consistency states, "The Environmental Qualification (EQ) of Electric Components Program is consistent with the program described in NUREG-1801, Section X.E1, Environmental Qualification (EQ) of Electric Components." LRA Section B.1.13 takes no exceptions to NUREG-1801, Section X.E1. The CNS B.1.13 program is fully consistent with the acceptance criteria of NUREG-1801, Section X.E1, including the phrase "continued qualification for the projected accident conditions."

NRC Request: *RAI B.1.13-2*

Background:

NUREG- 1801, Rev 1, X.E1, Program Element states:

> *Operating Experience: EQ programs include consideration of operating experience to modify qualification bases and conclusions, including qualified life. Compliance with 10 CFR 50.49 provides reasonable assurance that components can perform their intended functions during accident conditions after experiencing the effects of inservice aging.*

A review of CNS-RPT-07-LRD05 condition reports for electrical, instrument, and control components did no clearly differentiate condition reports relating to EQ. The EQ program operating experience is not referenced in B.1.13 including information and discussion on the EQ improvement project.

<u>*Issue:*</u>

A review of CNS-RPT-07-LRD05 condition reports for electrical, instrument, and control components did no clearly differentiate condition reports relating to EQ. The EQ program operating experience is not referenced in B.1.13 including information and discussion on the EQ improvement project.

<u>*Request:*</u>

Please provide representative recent operating experience (post EQIP) for electrical components related to EQ. In addition provide a summary discussion related to B.1.13 to include a discussion on the EQ improvement project.

<u>NPPD Response</u>:

<u>EQIP Summary</u>

In 2001, CNS initiated the Environmental Qualification Improvement Project (EQIP) because of 10 CFR 50.49 compliance issues. CNS documented three significant issues associated with the EQ program. The root cause for one of the issues was the omission of the Small Steam Line Break (SSLB) inside Containment from the CNS Design Basis as the most severe design basis event in the drywell. To address the root cause, a site specific SSLB was created and incorporated into the CNS EQ Program. The root cause of the second issue was that the process of translating and transmitting EQ information from the fundamental Environmental Qualification Data Package (EQDP) test configuration documents to the people making splices in the field was less than adequate. To address the root cause, additional procedure controls and training was implemented. The remaining issue root cause was a lack of commitment to EQ program implementation in that existing EQ program standards and expectations were not effectively communicated, implemented, and enforced. To address the root cause, the EQIP was developed. The EQIP was completed in two main phases. The first phase restored Program compliance with 10 CFR 50.49. Program documentation updates and field verifications were performed, with CNS restoring compliance with 10 CFR 50.49 on June 30, 2003. Subsequent to the completion of the first phase, the NRC performed a 10 CFR 50.49 compliance audit on October 6-10, 2003. This audit was completed with no findings or recommendations reported. The second phase was to complete the development, review, and update of EQ and plant affected documentation using the new EQ Environmental Conditions. Program documentation and procedures were re-formatted and enhanced. Based on follow-up audits, there has been no recurrence of the three significant issues.

CNS LRA Section B.1.13, Recent Operating Experience

In 2007, the quarterly health report for the EQ program indicated that the cornerstones for program infrastructure, implementation, and monitoring were acceptable. Program personnel qualification was identified as an area for improvement. The basis for this finding was a program owner that was new in his position that had not completed his qualifications, which were being actively pursued.

Since the EQIP was completed, the CNS EQ Program has been effective at managing aging effects. The EQ Program provides assurance that the effects of aging will be managed such that the applicable components will continue to perform their intended functions consistent with the current licensing basis for the PEO.

NRC Request: *RAI B.1.14-1*

Background:

GALL AMP XI.M36 states that this program is limited to the detection of loss of material due to general, pitting and crevice corrosion for components fabricated of steel only. Further, the GALL Report, NUREG-1801, Vol. 2, Rev. 1, in Section IX, p.IX-12, provides a definition of "steel" as:

> *For a given environment, carbon steel, alloy steel, cast iron, gray cast iron, malleable iron, and high strength low alloy steel are vulnerable to general, pitting, and crevice corrosion, even though the rates of aging may vary. Consequently, these metal types are generally grouped for AMRs under the broad term "steel. Note that this does not include stainless steel.*

Issue:

In the External Surfaces Monitoring Program basis document, CNS-RPT-07-LRD07, the applicant credits the External Surfaces Monitoring program with managing the loss of material in aluminum, copper alloy, gray cast iron, nickel alloy, and stainless steel components.

Request:

(a) *Provide additional information to justify the basis for expanding the scope of material beyond steel components as recommended by GALL AMP XI.M36*

(b) *Provide justification that the CNS External Surfaces Monitoring Program will manage aging effects for these additional materials included in the scope of the program*

(c) *Why is crediting this program for managing loss of material for aluminum, copper alloy, gray cast iron, nickel alloy and stainless steel components not considered an exception to the GALL Report*

NPPD Response:

(a) The External Surfaces Monitoring Program as defined by NUREG-1801 and as described in the LRA is based on the well established industry practice of periodic walkdowns of a system, typically by the system "expert" or system engineer. During the walkdown, the system engineer visually checks a variety of system characteristics, including the physical condition of equipment. The inspection of the external surfaces of equipment includes all components, not just steel components. Consequently, crediting the External Surfaces Monitoring Program for the management of loss of material for materials other than steel, is a reasonable application of an existing inspection process.

NUREG-1801 credits the External Surfaces Monitoring Program to manage loss of material for steel (including gray cast iron) in three air environments; indoor uncontrolled, outdoor, and with condensation. The focus of the NUREG-1801 program is reasonable since steel is the most common material used for mechanical systems and since steel is more susceptible to corrosion than other materials. But the program description does not suggest that the program cannot be applied to other materials.

(b) Aluminum, copper alloy, nickel alloy and stainless steel are not susceptible to loss of material due to general corrosion in indoor air. Some corrosion, in the form of pitting and crevice corrosion is possible for these materials when wetted, as with the environments of outdoor air or condensation. Pitting and crevice corrosion in these materials is not as readily observable as general corrosion in steel, but it typically develops more slowly and is detectible by visible evidence of stains and pits long before it affects the intended function of a component. This makes the external surfaces monitoring program an effective means of managing loss of material for these materials.

(c) As stated in NUREG-1800, Section 3.0.1, "Exceptions are portions of the GALL Report Aging Management Program (AMP) that the applicant does not intend to implement." Since CNS intends to implement all portions of the NUREG-1801 defined program, there are no exceptions. And, since the existing program already includes inspections of these additional materials, their inclusion is not considered an enhancement, which NUREG-1800, Section 3.0.1 defines as "revisions or additions to existing aging management programs that the applicant commits to implement prior to the period of extended operation."

NRC Request: *RAI B.1.14-2*

Background:

GALL AMP XI.M36 states that surfaces that are inaccessible or not readily visible during both plant operations and refueling outages are inspected at such intervals that would provide reasonable assurance that the effects of aging will be managed such that applicable components will perform their intended function during the period of extended operation.

Issue:

The CNS External Surfaces Monitoring Program basis document, CNS-RPT-07-LRD07, states that surfaces that are inaccessible or not readily visible during both plant operations and refueling outages are inspected at such intervals that would provide reasonable assurance that the effects of aging will be managed such that applicable components will perform their intended function during the period of extended operation. The referenced document, Section 5.1.2 of 98-03-04, does not state when and how these surfaces will be inspected.

Request:

(a) *What are the components that are not accessible during both plant operations and refueling outages?*

(b) *How will they be inspected and at what frequency will they be inspected to assure that aging effects will be managed during the period of extended operation?*

NPPD Response:

Components that are inaccessible or not readily visible during both plant operations and refueling outages include components in physically confined locations that prevent direct inspection; e.g., piping in a chase with other pipes can present such a configuration. Some components are also inaccessible for personnel safety reasons; e.g., components located in a high radiation area.

The specific components that credit the External Surfaces Monitoring Program to manage loss of material have been identified. Some components that credit the program for license renewal are not inspected because of their inaccessibility. However, the condition of these components is well represented by accessible components inspected during the comprehensive system walkdowns under the External Surfaces Monitoring Program. Just as NUREG-1801, XI.M36, permits the inference of internal surface conditions when the component's internal and external environments are the same, the condition of an inaccessible component can be inferred from an accessible system component of the same material in the same environment. Should degradation of accessible components be identified, evaluation of acceptability of inaccessible components is a standard part of determining the extent of significant conditions under the corrective action program.

NRC Request: *RAI B.1.14-3*

Background:

GALL AMP XI.M36 states that this program may also be credited with managing loss of material from internal surfaces, for situations in which material and environment combinations are the same for internal and external surfaces such that external surface condition is representative of internal surface condition. When credited, the program should describe the component internal environment and the credited similar external component environment inspected.

Issue:

The CNS Aging Management Program Evaluation Report, CNS-RPT-07-LRD07, in Section 4 credits this program for managing loss of material for internal surfaces by visual inspection of the external surfaces for carbon steel components. It also specifies the systems for which the internal surfaces of components will be credited under this program. The aging management review documents for specific systems provide general descriptions of the environment, e.g., air indoor (int.) and air indoor (ext.) for general component groups, e.g., pipes.

Request:

Provide the documentation or the method of documenting for each component the internal surface environment and the corresponding similar external surface environment for the internal component surfaces for which this program is being credited.

NPPD Response:

The External Surfaces Monitoring Program is credited for managing loss of material for the internal surface of a component when the component's external environment is the same or more limiting than the internal environment, and the external surface is inspected by the program. This internal/external pairing is documented by pairs of lines in the aging management review results tables, Tables 3.X.2-Y, in Section 3 of the LRA. For each table line where the External Surfaces Monitoring Program is credited for an internal surface, e.g., where the listed environment is air – indoor (int), the same component type will have a corresponding line crediting this same program for the external surface, e.g., with the listed environment as air – indoor (ext).

These internal/external pairings are also summarized by system and component type in the CNS aging management program evaluation report for the External Surfaces Monitoring Program. The information in this report is reproduced in tabular form below.

AMR Report	System	Material	Component Types	Internal Environment	External Environment
AMM06	residual heat removal system	carbon steel	piping, trap and valve bodies	indoor air	indoor air
AMM07	high pressure coolant injection system	carbon steel	piping and valve bodies	indoor air	indoor air
AMM08	automatic depressurization system	carbon steel	piping and valve bodies	indoor air	indoor air
AMM10	standby gas treatment system	carbon steel	damper housings, fan housings, piping and valve bodies	indoor air	indoor air
AMM10	standby gas treatment system	carbon steel	piping	outdoor air	outdoor air
AMM11	plant drains	carbon steel	piping and valve bodies	indoor air	indoor air
AMM11	plant drains	carbon steel	piping and valve bodies	outdoor air	outdoor air
AMM13	diesel generator system	carbon steel	accumulators, filter housings, heat exchanger housings, piping, turbochargers, and valve bodies	indoor air	indoor air
AMM13	diesel generator system	carbon steel	crankcase breathers (piping components)	indoor air	outdoor air
AMM14	diesel fire pump fuel oil system	aluminum	flame arrestors	outdoor air	outdoor air
AMM14	diesel fire pump fuel oil system	gray cast iron	flame arrestors	outdoor air	outdoor air
AMM14	diesel fuel oil systems	carbon steel	piping	indoor air	indoor or outdoor air

AMR Report	System	Material	Component Types	Internal Environment	External Environment
AMM15	fire protection system	carbon steel	diesel fire pump air intake duct, fire water system piping and nozzles	indoor air	indoor air
AMM17	heating, ventilation and air conditioning system	carbon steel	filter housings, heat exchanger housings, restriction orifices, and valve bodies	indoor air	indoor air
AMM17	heating, ventilation and air conditioning system	carbon steel	damper housings, duct, fan housings, and louver housings	indoor air	indoor or outdoor air
AMM18	primary containment system	carbon steel	piping and valve bodies	indoor air	indoor air
AMM20	primary containment system	carbon steel	damper housings	indoor air	indoor air
AMM20	heating, ventilation and air conditioning system	carbon steel	damper housings, duct, fan housings, and flow elements	indoor air	indoor or outdoor air
AMM20	radiation monitoring — ventilation system	carbon steel	piping and valve bodies	indoor air	indoor air
AMM24	nitrogen system	carbon steel	piping and valve bodies	indoor air	indoor or outdoor air
AMM24	nitrogen system	gray cast iron	valve bodies	indoor air	indoor or outdoor air

NRC Request: *RAI B.1.14-4*

Background:

GALL AMP XI.M36 states that degradation of steel surfaces cannot occur without the degradation of the paint or coating. Confirmation of the integrity of the paint or coating is an *effective method for managing the effects of corrosion on steel surfaces but not for stainless steel.*

Issue:

The CNS Aging Management Program Evaluation Report states that the program also manages the aging effects of aluminum, copper alloy, gray cast iron, nickel alloy, and stainless steel surfaces. The document further states that general corrosion of these surfaces will manifest itself as visible rust or rust byproducts (e.g., discoloration or coating degradation) and be detectable prior to any loss of intended function.

Request:

Provide justification for claiming that general corrosion of surfaces of materials such as aluminum, copper alloy, gray cast iron, nickel alloy, and stainless steel that CNS is crediting under this program would manifest itself as visible rust or rust byproducts. Also, the staff questions whether general corrosion of stainless steel surfaces would manifest itself as visible rust or rust byproducts as this is not consistent with the GALL Report.

NPPD Response:

Rust is typically associated with the general corrosion of steel (including gray cast iron). Aluminum, copper alloy, nickel alloy and stainless steel are not susceptible to loss of material due to general corrosion but are susceptible to pitting and crevice corrosion. Corrosion of these materials would not appear as common rust, but would still be visible as discoloration of the material (stains), corrosion product deposits, pitting, or coating degradation if the material were coated. These conditions can be observed on the surface of affected components through visual inspections long before intended functions will be affected.

NRC Request: *RAI B.1.14-5*

Background:

GALL AMP XI.M36 states that the External Surfaces Monitoring Program uses standardized monitoring and trending activities to track degradation. Deficiencies are documented using approved processes and procedures such that results can be trended.

Issue:

The CNS Aging Management Program Evaluation Report, CNS-RPT-07-LRD07, states that deficiencies are documented so that results can be trended. The referenced documents, Section 4 of Systems Engineer Desktop Guide, 98-03-04, and Section 2 of Administrative Procedure 0.5

CR, discuss the philosophy of systems walkdowns and when and how to write a CR. However, these documents do not describe the trending activities.

Request:

Describe the trending activities that will be used at CNS. How does the program track reoccurrence of conditions? How does the program provide predictability of the extent of degradation and thus timely corrective or mitigative actions?

NPPD Response:

Section 4 of Systems Engineer Desktop Guide, 98-03-04, and Section 2 of Administrative Procedure 0.5 CR, discuss the philosophy of system walkdowns and when and how to write a condition report as part of the corrective action program. The corrective action program provides the trending needed to support the External Surfaces Monitoring Program.

Systems Engineer Desktop Guide, 98-03-04, describes the system engineer's role in conducting system walkdowns (the process by which the External Surfaces Monitoring Program is conducted), emphasizing the importance of being familiar with the condition of his or her system. Although informal, trending by repetitive observations is effective for monitoring minor component degradation such that timely corrective or mitigative actions can be taken based on the extent and rate of change of degradation. If the degradation warrants, a condition report is written. The corrective action program also includes provisions for timely corrective or mitigative actions of individual equipment problems, trending of repetitive equipment degradation, and identification of adverse equipment trends.

NUREG-1801 acknowledges that qualitative trending processes are sufficient for this program. As stated in the Trending and Monitoring section of XI.M36, "the program does not include formal trending."

NRC Request: *RAI B.1.14-6*

Background:

GALL AMP XI.M36 states that for each component/aging effect combination, the acceptance criteria are defined to ensure that the need for corrective actions will be identified before loss of intended functions. Acceptance criteria include design standards, procedural requirements, current licensing basis, industry codes or standards, and engineering.

Issue:

The CNS Aging Management Program Evaluation Report states that engineering evaluations consider procedural requirements, current licensing basis, industry codes but does not specify the specific codes and standards.

Request:

Cite the specific codes or standards that will be used to determine acceptability. At what point or what criteria are used to decide when corrective actions will be implemented?

NPPD Response:

The External Surfaces Monitoring Program is credited for managing loss of material due to corrosion. Detection of corrosion is by visual inspection during the system walkdown. System walkdown procedures provide guidance for the inspections. System engineer experience and training on systems and the site corrective action program provide assurance that visual indications of corrosion will be entered into the CNS corrective action program well before component intended functions are affected.

The corrective action program ensures timely evaluation and corrective action of conditions identified by the system walkdown. As necessary, engineering evaluations of the condition will consider relevant procedural requirements, current licensing basis, industry codes, and standards to decide when corrective actions will be implemented. These requirements, codes and standards used in the evaluation, which are part of the current plant design basis, will depend on the system, the component and the condition. Some typical standards would be the ASME Code and site piping specifications or pressure temperature calculations that provide pipe wall thickness requirements.

NRC Request: *RAI-B.1.14-7*

Background:

CNS has added an enhancement to the External Surfaces Monitoring Program to enhance the guidance documents to clarify that inspections of systems within the scope of license renewal will be inspected. Also, the enhancement adds inspections of surrounding areas to indentify hazards to the subject systems and inspections of nearby systems that could impact the subject systems.

Request:

Provide examples of

(a) *hazards in areas surrounding the subject systems and*

(b) *SSCs in nearby systems that could impact the subject systems that are in the scope and subject to aging management for review for license renewal in accordance with 10 CFR 54.4 (a)(2) that will be inspected under this enhancement.*

NPPD Response:

(a) The enhancement to the External Surfaces Monitoring Program will expand system walkdowns to include areas surrounding the subject systems to identify hazards to those systems. Examples of the types of hazards these systems could present include physical impact; pipe whip, jet impingement, spray, leakage or flooding. Section 2.1.1.2.2 of the LRA describes these hazards.

(b) Inspections of nearby systems that could impact the subject systems will include structures, systems, and components (SSCs) that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2). The enhancement will focus the walkdown inspections on surrounding mechanical systems. Structures and structural components will be inspected by the Structures Monitoring Program. The External Surfaces Monitoring Program will inspect components containing oil, steam or liquid and located in spaces containing safety-related equipment. Tables 3.2.2-8-1 through 3.2.2-8-6, 3.3.2-14-1 through 3.3.2-14-29, and 3.4.2-2-1 through 3.4.2-2-13 present the systems and components in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2). The components that credit the External Surfaces Monitoring Program to manage loss of material and its potential impact on safety-related components in the area are identified in these tables.

NRC Request: *RAI B.1.15-1:*

Background:

Program Element 2 of NUREG-1801 (GALL Report) Section X.M1 is concerning preventive actions. For Program Element 2, the GALL Report states: "Maintaining the fatigue usage factor below the design code limit and considering the effect of the reactor water environment, as described under the program description, will provide adequate margin against fatigue cracking of reactor coolant system components due to anticipated cyclic strains".

Under the CNS Fatigue Monitoring program, B.1.15 (CNS-RPT-LRD02, Revision 1), program element 2 subsection b states that: "The Fatigue Monitoring Program uses the systematic counting of design cycles and the evaluation of operating data to ensure that component design fatigue limits are not exceeded...". In this same subsection, it brings up an Enhancement clause, stating that "Consideration of the effect of the reactor water environment will be accomplished through implementation of one or more of the following options for the feedwater nozzles, core spray nozzles and RHR pipe transition."

Issue:

There is no discussion on why the FMP is limited only to 3 locations.

Request:

(a) *Describe the locations that are monitored in the FMP for license renewal. If the program is limited only to 3 locations, please provide justification.*

(b) *Clarify the parameter CUF stated in bullet (2) of element 2 subsection b. Does it account for environmental effects? Or not?*

NPPD Response:

(a) The Fatigue Monitoring Program (FMP) at CNS counts the occurrence of transients and compares the actual cycles incurred to the analyzed cycles for all the components at CNS. As a cycle based program, it is not limited to specific components, but covers all components with analyzed cycle limits.

The enhancement addresses the consideration of environmentally assisted fatigue. As discussed in LRA Section 4.3.3, CNS has applied environmental correction factors to fatigue analyses for the six locations identified in NUREG\CR-6260 for a BWR of Cooper's vintage. As shown in LRA Table 4.3-3, the six locations from NUREG\CR-6260 equated to nine plant-specific locations at CNS. Of those nine locations, six were shown to be acceptable based on re-analysis and the application of F_{en} factors. The remaining three locations (FW nozzles, core spray nozzles and RHR pipe transition) are addressed by the subject enhancement to the FMP. Cycle counting during the PEO confirms the ongoing validity of the assumed numbers of cycles in all of the fatigue analyses that are based on assumed numbers of cycles.

(b) The parameter CUF stated in CNS-RPT-LRD02, Revision 1, Section 4.7 B.2b bullet (2) is the CUF adjusted for environmental effects. LRA Section A.1.1.15 and LRA Section B.1.15 are revised to change "a CUF" to "an environmentally adjusted CUF" in enhancement item (2) (see Attachment 2).

NRC Request: *RAI B.1.15-2:*

Background:

Program Element 3 of NUREG-1801 (GALL) Section X.M1 is concerning with parameter monitored/inspected. GALL requires the program to monitor all plant transients that cause cyclic strains, which are significant contributors to the fatigue usage factor.

Issue:

The CNS FMP only monitors the design cycles assumed in the RCS component design analyses.

Request:

(a) Please list those transients that would contribute to fatigue usage but are not included in the design transients and update CNS FMP Element 3 accordingly.

NPPD Response:

(a) The FMP tracks transients that contribute to fatigue usage in current licensing basis fatigue calculations. This includes calculations performed after initial component design. NPPD has added analyzed transients to the FMP as they have been identified and thus Table 4.3-1 lists more transients than the transients identified in USAR Table III-3-1 including transients discussed in other RAIs, such as FW cycling and turbine roll. The projected transients in LRA Table 4.3-1 represent the transients currently counted at CNS, and includes all the transients identified to date that would contribute to fatigue usage at CNS (transients with an unreachable number of analyzed cycles are not counted). The actuation of a safety/relief valve was recently identified as a transient for the primary containment to be recorded as input to the FMP, as documented in the second enhancement for this AMP.

NRC Request: *RAI B.1.15-3:*

The NRC sent a revision to this RAI in a separate letter (ADAMS Accession Number ML091530316). No NPPD response is required at this time.

NRC Request: *RAI B.1.15-4:*

The NRC sent a revision to this RAI in a separate letter (ADAMS Accession Number ML091530316). No NPPD response is required at this time.

NRC Request: *RAI B.1.15-5:*

Background:

Program Element 10 of NUREG-1801 (GALL Report) Section X.M1 is concerning with operating experience. For Program Element 10, the GALL Report states: "The program reviews industry experience regarding fatigue cracking. Applicable experience with fatigue cracking is to be considered in selecting the monitored locations". Under the CNS Fatigue Monitoring program, B.1.15 (CNS-RPT-LRD02, Revision 1), Program Element 10 subsection b states: "Operating experience shows that this program has been effective in managing aging effects ..."

Issue:

The "operating experience" program element of the Fatigue Monitoring Program, B.1.15 made no mention about industry operating experience of any kind. The only operating experience presented is concerning transient cycle tracking of CNS' own plant.

Request:

(a) Describe the documents that CNS has reviewed in considering the industry experience on metal fatigue and provide the corresponding follow-up actions taken by CNS.

(b) List industry experiences which have been incorporated into the CNS Fatigue Monitoring Program.

NPPD Response:

(a) CNS has reviewed NRC documents (information notices, bulletins, regulatory issue summaries, and regulatory guides), vendor notices, Nuclear Energy Institute (NEI), INPO and EPRI documents, and other utility LRAs. Specific documents include RIS 2008-30, NUREG/CR-6260, GE notices on FW cycling, and recent LRAs.

(b) Industry experience incorporated into the CNS FMP includes the following:

1. Industry experience has identified that the effects of reactor coolant environment on fatigue, which were not considered in the original design of CNS, should be addressed for the PEO. Environmental effect analyses have been performed for license renewal and ongoing activities prescribed by the FMP include consideration of environmental effects.

2. NRC document RIS 2008-30 deals with the use of an analysis method to demonstrate compliance with the ASME Code fatigue acceptance criteria that

could be nonconservative if not correctly applied. NPPD has not used this method for any EAF fatigue analyses. No changes were required to the CNS program.

3. Vendor (GE) notices identified FW cycling phenomena observed during plant operation. In response, NPPD revised FW nozzle fatigue analyses to account for this phenomenon.

NRC Request: *RAI B.1.15-6:*

Background:

Engineering Procedure 3.20 provides for collection of RPV operational transients, as implemented by the Fatigue Monitoring Program.

Issue:

Engineering Procedure 3.20 does not provide criteria defining "a transient."

Request:

(a) The record for 2003 states that the SCRAM on 12/2/02 "is not recorded as a transient." What were the thermal and pressure characteristics of this SCRAM and why was it not identified as a transient?

(b) The record for 2003 also identifies a new transient on 4/20/00.

- *Why was this transient not identified contemporaneous with its occurrence? If this was due to a redefinition of conditions that qualify as a transient, were there other newly identified transients?*

- *What corrective actions were implemented to ensure that future transients would not be missed?*

NPPD Response:

(a) The scram that occurred on 12/2/02 was a manual scram during start-up. There was no significant impact on the vessel temperature or pressure. Per Attachment 3 of Procedure 3.20, temperature changes ≤ 25 °F or pressure changes ≤ 50 psig are considered insignificant.

(b) The vessel was being warmed up for the ASME Section XI pressure test with Reactor Recirculation (RR) Loop A in service at 200 °F. When RR Loop B reactor recirculation pump was started the coolant temperature in RR Loop B went from 80 °F to 200 °F in 30 minutes. Although RR Loop B temperature changed, the vessel temperature readings remained between 150 °F and 200 °F during this period. Since the temperatures were on the right side of the Pressure-Temperature curve and the reactor vessel was vented during this event (there was no pressure increase), this condition did not exceed the minimum vessel metal temperature limits specified in Technical Specification Figure 3.4.9-2 and as such is not a counted transient.

This event was not identified as a transient by Operations when it occurred. It was identified later during review of the last two performances of the reactor vessel ASME Section XI pressure test. No program modification was necessary as the event was correctly handled by the existing procedure.

NRC Request: *RAI B.1.15-7:*

Background:

Under the Program Description of the Fatigue Monitoring Program, B.3.1.15, the LRA states that "the program ensures the validity of analyses that explicitly assumed a fixed number of thermal and pressure transients by assuring that the actual effective number of transients does not exceed the assumed limit."

Issue:

In the LRA, there was no description or discussion regarding how CNS has been and will be monitoring the severity of pressure and thermal (P-T) activities during plant operations. It is essential that all thermal and pressure activities (transients) are bounded by the design specifications (including P-T excursion ranges and temperature rates). Furthermore, cycles of all significant thermal events should be captured and logged.

Request:

(a) Describe the procedures that CNS uses for tracking thermal transients.

(b) Confirm that all monitored transient events are bounded by the design specifications.

(c) Specify the time (years) over which actual transient monitoring and cycle tracking activities took place. If there have been periods where transient data were not recorded since the initial plant startup specify the affected time frame. For the time periods for

which transients were not monitored, provide justification to demonstrate that the projected cycles for this unmonitored period are conservative.

(d) *Provide a histogram of cycles accrued for normal start and normal shutdown transients.*

(e) *"Background" paragraph above indicates that the CNS Fatigue Monitoring Program is based on an assumed number of cycles of transients to ensure the validity of analyses. Describe how those assumed number of cycles were established and explain why the assumed number of cycles can be used as basis to validate the Fatigue Monitoring Program.*

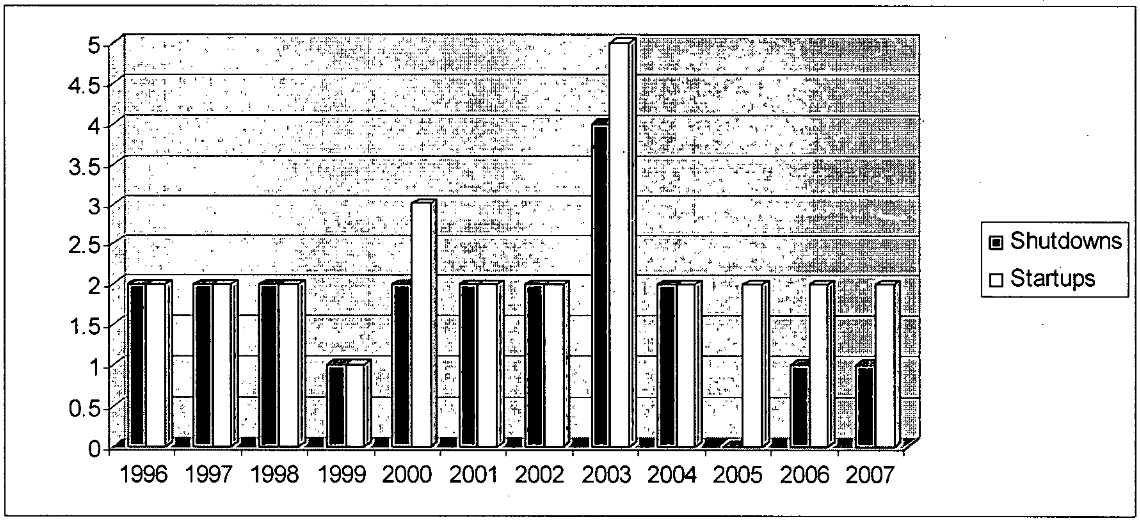
NPPD Response:

(a) CNS uses the thermal transient review procedure for tracking thermal transients. This procedure requires CNS engineering to count all transients each fuel cycle. The procedure requires the review of plant operating data (initiator, temperatures, pressures, levels, etc.) and comparison of each transient to the transients defined in the design documents. CNS Design Engineering Department management reviews each transient classification.

(b) The cycles counted in the thermal transient review procedure are compared to the transient definitions in the design documents. Each event that occurs is counted as the next most severe transient that bounds that event; consequently the vast majority of counted transients are significantly less severe than the corresponding transient definitions in the design documents. The thermal transient review procedure requires additional actions beyond simple cycle logging if the parameters in design documents are exceeded. CNS would initiate a condition report as part of the corrective action program and evaluate in accordance with site quality assurance procedures that meet 10 CFR 50 Appendix B requirements.

(c) The initial transient review procedure was issued in the mid 1980s. Prior to the issuance of that procedure, plant logs and other documents were reviewed to determine the transients that had occurred. There have been no time periods for which transient data has not been accounted for in the program.

(d) A histogram of the startups and shutdowns from 1996 to 2007 is provided below.



(e) Each fatigue analysis is based on an assumed number of transients. The reactor vessel original equipment manufacturer, GE, established analysis assumptions regarding the numbers of postulated transients during the original plant design. Additional analyses have either been based on the same numbers of design transients, or additional transients have been added to the list being tracked by the transient review procedure. These cycles represent the correct numbers of cycles to monitor with the FMP because they are the numbers of cycles upon which the analyses of record are based. The assumed numbers of cycles are not used as basis to validate the FMP. Rather, the FMP tracks actual cycles against these assumed numbers of cycles, and requires action before the analyzed numbers of cycles are reached, thereby assuring that the analyses remain valid.

<u>NRC Request</u>: *RAI B.1.15-8*

<u>Background:</u>

Under the Program Description of the Fatigue Monitoring Program, B.3.1.15, the LRA states "This program also addresses the effects of the coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant." Analysis concerning the effects of reactor water environment on fatigue is provided in LRA Section 4.3.3 and the results are presented in LRA Table 4.3-3.

The SRP provides guidance to review effects of the reactor coolant environment on the fatigue life.

Issue:

Note 2 under Table 4.3-3 of the LRA states that "F_{en} are based on the specific oxygen concentrations at each specific location, adjusted for the time spent with normal water chemistry and the time spent with hydrogen water chemistry". It is noted that value of F_{en} depends on the material of the structural component, strain rates, operating temperature and chemistry of the reactor water. However, information or technical discussions are not provided in the LRA.

Request:

(a) *Specify the analysis method(s) used for computing fatigue usage factors (CUF) for all Class 1 components, including NUREG/CR-6260 locations. Clarify whether any of the CUF values shown in LRA Tables 4.3-2 and 4.3-3 were calculated using FatiguePro, which considers only a single component of a stress tensor. If the answer is positive, describe the corrective actions taken or commitments.*

(b) *Provide a summary of the environmental factor (F_{en}) calculation for each structural component analyzed, including the values of dissolved oxygen (DO) level, temperature and strain rate used in the calculations.*

(c) *Describe the equation that was used for the time and water chemistry adjusted F_{en} calculations.*

(d) *Summarize CNS's experience in control of DO concentration in the reactor water since the plant startup. Describe all water chemistry programs CNS has used, including procedures and requirements used for managing DO concentration as well as the inception date of each water chemistry program.*

(e) *Describe the control parameters used to maintain and demonstrate chemistry control, and how the dissolved oxygen values vary with the expected and acceptable variations in these parameters.*

(f) *Describe how chemistry upset conditions have been considered in the F_{en} calculations.*

NPPD Response:

(a) None of the CUFs of record in the current licensing basis were calculated using FatiguePro. The CUFs in LRA Table 4.3-2 are CUFs of record. These were typically calculated using classical finite element analysis, considering six components of stress.

The CUFs in LRA Table 4.3-3 were generated for the LRA to address environmentally assisted fatigue by applying environmental adjustment factors (F_{en}). For the locations evaluated, fatigue calculations were in accordance with the 1998 Edition, 2000 Addenda of the ASME Code. This involves applying a Young's Modulus correction factor (i.e., $E_{fatigue\ curve}/E_{analysis}$) to the calculated stresses, applying K_e where appropriate, and utilizing the 2000 Addenda fatigue curve. FatiguePro was not used in calculating the fatigue usage factors, and six components of stress were considered.

(b)(c) The following table is an extension of LRA Table 4.3-3, showing the values of dissolved oxygen (DO) used in the calculations. Constant values were used for sulfur (0.015 wt%), temperature (550 °F) and strain rate (0.001 %/s) for all F_{en} calculations. The equations used for the F_{en} calculations are the equations from NUREG/CR-6853 for carbon and low-alloy steel and NUREG/CR-5704 for stainless steel. An F_{en} was calculated for hydrogen water chemistry (HWC) and an F_{en} was calculated for normal water chemistry (NWC), and a combined F_{en} was determined using weighting factors of 49.1% for HWC and 50.9% for NWC.

NUREG-6260 Components		**Material**	**40-Year Design CUF**	**60-Year CUF**	**Fen**	**60-Year EAF CUF**	**DO (ppm)**	
							NWC	**HWC**
1	Reactor vessel shell and lower head (CRD pen)	Alloy 600	0.86	0.4956	1.49	0.7384	0.165	0.035
2	Reactor vessel feedwater nozzle	LAS	1.06	1.0285	10.4	10.701	0.144	0.088
3	Reactor recirculation piping (inlet nozzle safe end)	SA-182 Gr 316NG	0.38	0.0452	8.36	0.3774	0.167	0.014
3	Reactor recirculation piping (outlet nozzle safe end)	SA-182 F304	0.01	0.0117	8.36	0.0976	0.167	0.014
4	Core spray piping reactor vessel (nozzle safe end)	SA-182 Gr 316NG	0.193	0.0176	8.36	0.1467	0.123	0.093
4	Core spray reactor vessel nozzle	A533 B(1) / A508	0.03	0.1451	10.4	1.5095	0.123	0.093
5	Residual heat removal return line Class 1 piping (RHR tee)	SA-312 Type 316	0.896	0.0573	11.79	0.6761	0.167	0.014
5	Residual heat removal return line Class 1 piping (transition piece)	A-155 KC-70 (CS)	1	0.5967	7.83	4.6742	0.167	0.014
6	Feedwater (FW) line Class 1 piping (FW/RWCU/RCIC tee)	A-333 Gr 1 (CS)	0.664	0.0683	2.1	0.1435	0.036	0.051

(d) NWC results in a DO concentration of approximately 150 to 180 ppb. This concentration was present from plant start-up in 1974 to August of 2003. In August 2003, CNS began hydrogen injection via FW, referred to as HWC. Numerous measurements during use of NWC were made using the RR/RWCU inlet sample point. These measurements were consistent with the approximately 150 to 180 ppb DO value expected using NWC. Reactor DO measurements made during HWC, using the RR/RWCU inlet sample point, were reduced to approximately 3 ppb.

The measurements that have been made are only on the RR/RWCU inlet sample point. This does not reflect the DO values inside the reactor vessel. To determine the DO values for locations inside the reactor vessel, the BWRVIP Radiolysis Model is used. The model shows that during NWC, internal reactor vessel locations show a range of DO concentration from approximately 90 ppb to approximately 120 ppb with the RR/RWCU inlet sample point reading approximately 120 ppb. The model results are reasonable when compared to actual measurements.

During HWC, the model shows DO concentrations in the reactor vessel from as low as approximately 4 ppb at the RR/RWCU inlet sample point to approximately 90 ppb in the upper plenum. The bulk of the reactor locations would have DO concentrations < 50 ppb. Again, the model results are reasonable when compared to actual measurements.

CNS uses hydrogen injection in conjunction with noble metals chemical application (NMCA). Even though NMCA was performed in March of 2000, no change in DO occurred until actual hydrogen injection was initiated in August 2003.

(e) The DO concentration in the reactor is a function of temperature and pressure. During HWC, the DO concentration is controlled by the injection of hydrogen. At the time of the initial injection of hydrogen, a ramp test was performed to determine the amount of hydrogen necessary to reduce the electrochemical corrosion potential (ECP) to a value low enough to suppress IGSCC. Once the minimum hydrogen injection value was determined, additional hydrogen flow was added to provide margin. The final hydrogen flow rate into FW was established at 7.5 scfm. The hydrogen injection flow rate is the only control parameter utilized. Chemistry records the hydrogen flow rate as well as the calculated ECP. The radiolysis model confirms that the H_2 to O_2 molar ratio is > 2 at locations within the reactor. These measurements track and confirm that the appropriate amount of hydrogen is added.

The single indicator used to indicate when hydrogen injection is in service is HWC availability. HWC availability is the percentage of time reactor temperature is > 200 °F and hydrogen injection is in service. The goal is to maintain > 98% HWC availability.

(f) Chemistry upsets were not considered in the calculation of F_{en} for the environmental fatigue analyses. The chemical conditions in the vessel do not change rapidly and chemistry upsets are not significant to fatigue if no design transient occurs during the chemistry upset.

NRC Request: *RAI B.1.16-1*

Background:

In its LRA, CNS proposed an 18-month functional testing cycle to the Halon & CO_2 fire suppression systems as exceptions to the NUREG-1801 program, which calls for a 6-month cycle. The Exception Notes at the bottom of page B-50 state, in part that "This frequency is sufficient based on station operating experience."

Issue:

It is not clear to the reviewer as to why the 18-month functional testing is sufficient based on station operating experience.

Request:

Please provide additional details on plant operating experience to justify the 18-month functional testing cycle, and (2) the specific edition/year of the NFPA 12 Standard on Carbon Dioxide Extinguishing Systems and NFPA 12A Standard on Halon 1301 Fire Extinguishing Systems Cooper references in its fire protection technical basis document. Please include the title and the document number of the technical basis document in the response.

NPPD Response:

Site operating experience was reviewed by performing keyword searches for "halon", "CO_2", and "carbon dioxide" in the corrective action database. The review found no instances of failures or adverse conditions for the Halon or CO_2 systems involving the ability of the system to perform its license renewal intended function. Inspection and testing frequencies for the CO_2 and Halon fire protection systems are specified in the approved CNS Technical Requirements Manual. The EPRI Fire Protection Equipment Surveillance Optimization and Maintenance Guide (1006756, Final Report, July 2003) recommends a functional testing interval of 18 months for Halon and CO_2 systems.

2) The CNS Fire Hazards Analysis (FHA) is the technical basis document citing use of NFPA 12 and NFPA 12A for activities associated with the Halon and CO_2 extinguishing systems. The specific edition of NFPA 12 is NFPA 12-1973, "Standard for Carbon Dioxide

Extinguishing Systems." The specific edition of NFPA 12A is NFPA 12A-1980, "Standard for Halon 1301 Fire Extinguishing Systems."

<u>NRC Request</u>: *RAI B.1.18-1*

<u>Background</u>:

GALL Section XI.M17, "Flow-Accelerated Corrosion," states:

> *The program relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R2 [Referencing Revision 2] for an effective flow-accelerated corrosion (FAC) program.*

<u>Issue</u>:

LRA Section B1.18, for Flow Accelerated Corrosion states: The program, based on EPRI recommendations in NSAC-202L for an effective flow-accelerated corrosion program, predicts, detects, and monitors FAC... Later in the same section, it notes that the program will be enhanced by updating the System Susceptibility Analysis to reflect lessons learned and new technology that became available after the publication of NSAC-202L, Revision 1.

Based on the program enhancement, the current program is based on NSAC-202L, Revision 1. However, the LRA does not state, that following the enhancements, all elements of the program will implement the guidance of NSAC-202L, Revision 2 or later.

<u>Request</u>:

Provide information to indicate that, with the enhancement, all of the elements within the flow accelerated corrosion program will implement the guidance of NSAC-202L, Revision 2 or later. Alternately, identify differences between the proposed program and Revision 2 and provide justification for the proposed program in managing FAC at Cooper.

<u>NPPD Response</u>:

The intent of the presentation in the LRA was that with the enhancement in LRA Section B.1.18, the program will be consistent with the NUREG-1801 program. Implementation of this enhancement will ensure that the elements within the flow accelerated corrosion program will implement the guidance of NSAC-202L, Revision 2.

NRC Request: *RAI B.1.18-2*

Background:

GALL Section XI.M17, "Flow-Accelerated Corrosion," for the program scope states, in part, that the guidelines in NSAC-202L program assure the structural integrity is maintained for all carbon steel lines containing high-energy fluids. There are no operational-time limitations discussed in this GALL program, relative to excluding systems from the scope of the program.

Issue:

The program description in LRA Section B.1.18, "Flow-Accelerated Corrosion," states, in part, that this existing program applies to systems containing high-energy fluids that operate "greater than or equal to two percent of plant operating time per the criteria given in EPRI NSAC-202L." Although the EPRI guidance document does state that systems in operation less than 2 percent of plant operating time can be excluded from the scope of the program, the sentences, which immediately follow, caution that:

> *...if service is especially severe (e.g., flashing flow), that system should not be excluded from evaluation based on operating time alone. A further caution – some lines that operate less than 2% of the time have experienced damage caused by FAC.*

Request:

Provide justification for excluding systems from the scope of the FAC program that operate less than two percent of the time and describe how the associated caution statements in NSAC-202L will be addressed.

NPPD Response:

The program description was not intended to imply a deviation from the guidance of EPRI NSAC-202L. The CNS program does not exclude systems from evaluation based on operating time alone. The program descriptions in LRA Section A.1.1.18 and B.1.18 are each hereby revised to delete the phrase "greater than or equal to two percent of plant operating time" (see Attachment 2).

<u>NRC Request</u>: *RAI B.1.18-3*

<u>Background</u>:

GALL Section XI.M17, "Flow-Accelerated Corrosion," states:

> *The program relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R2 [Referencing Revision 2] for an effective flow-accelerated corrosion (FAC) program.*

NSAC-202L, Section 5.2, "Training and Engineering Judgment" notes, in part, that training of key personnel is essential and that personnel involved in the program be trained in FAC.

Cooper Nuclear Station's (CNS) Engineering Procedure 3.10, "Erosion/Corrosion Program," Section 2.1, "Training and Qualification," states, in part, that CNS personnel responsible for implementing the erosion/corrosion program will be qualified to TQD 0993, Erosion/Corrosion Program Engineer.

<u>Issue</u>:

Based on discussions during the audit, CNS routinely uses non-CNS personnel to implement certain engineering aspects of the FAC program. However, the controlling procedure, as written, does not address any training for non-CNS personnel involved in the program.

<u>Request</u>:

Provide information relative to training that will be required for non-CNS personnel involved in implementing the FAC program. If training will not be required, justify how the recommendations in NSAC-202L, regarding personnel training, will be addressed.

<u>NPPD Response</u>:

LRA Sections A.1.1.18 and B.1.18 are revised as shown in Attachment 2 to reflect the enhancement to stipulate requirements for training and qualification of non-CNS personnel involved in implementing the Flow-Accelerated Corrosion (FAC) Program.

<u>NRC Request</u>: *RAI-B.1.18-4*

<u>Background</u>:

GALL Section XI.M17, "Flow-Accelerated Corrosion," for the program scope states:

> *...the program includes the use of a predictive code, such as CHECWORKS, that uses the implementation guidance of NSAC-202L-R2 to satisfy the criteria specified in 10 CFR Part 50, Appendix B, criteria for development of procedures and control of special processes.*

<u>Issue</u>:

*Based on discussions during the audit, CNS classifies CHECWORKS as Level C Software "Business Important" through CNS Operations Manual, Station Computer Procedure 11.2, "Software Classification." Within this procedure, it notes for Level B Software, "Licensing Basis" that this level is for software products "that are important to compliance with regulatory requirements/**commitments** [emphasis added by staff]. In light of CNS' implementation of regulatory commitments associated with the Erosion/Corrosion Program, it appears that CHECWORKS should be classified as a Level B Software, "Licensing Basis."*

<u>Request</u>:

Provide the basis for the current classification of CHECWORKS as Level C Software, "Business Important," and additionally address why it is not classified as Level B Software, "Licensing Basis."

<u>NPPD Response</u>:

The CHECWORKS software is used at CNS as a predictive tool for identifying locations potentially susceptible to the aging effect of FAC. The software is classified as Level C "Business Important" based on its use to provide information to plant management for decision-making activities which do not affect the immediate ability to operate the plant yet could threaten long-term operability.

The CNS site guidance for software classification describes Level B software as "software products used in Non Safety-Related (NSR) plant equipment that are subject to quality standards more stringent than those normally applied to NSR components." The CHECWORKS software is not used for the operation of any SSC nor is it used to verify compliance with the CNS Technical Specifications, or with regulatory requirements or commitments.

In response to NRC Bulletin 87-01 "Thinning of Pipe Walls in Nuclear Power Plants," CNS stated, in part, that "augmentation of the CNS program will include the use of these improved predictive models in the selection of single- and two-phase pipe inspection points." This statement was captured in the CNS commitment tracking system as a one-time commitment to augment the FAC Program, which has been implemented. CHECWORKS is not used to verify continued compliance with any regulatory requirement or commitment.

NRC Request: *RAI-B.1.19-1*

Background:

In the CNS LRA Section B.1.19, "Inservice Inspection," the applicant stated that, "The Inservice Inspection – ISI Program is consistent with the program described in NUREG-1801, Section XI.M1, ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, with exceptions." It further described the exception that NUREG-1801 recommends the use of ASME Section XI Table IWB-2500-1 to determine the examination of category B-F and B-J welds whereas CNS uses examination category R-A in accordance with risk-informed methodology approved by the NRC for examination of Table IWB-2500-1 category B-F and B-J welds.

Issue:

The applicant needs to provide technical basis why the proposed alternative meets guidance specified in NUREG-1801, Section XI.M1.

Request:

Please provide technical basis that the proposed alternative meets guidance specified in NUREG-1801, Section XI.M1. Specifically, what is the sampling size as a result of the risk-informed methodology for each ASME Code category for the current inspection period, compared to NUREG-1801 recommendation. Would the sampling size ever be zero for any category as the result of the proposed risk-informed methodology?

NPPD Response:

The number of B-F and B-J weld inspections before and after RI-ISI implementation is as follows:

Code Category B-F

There are a total of 28 B-F welds in the ISI program. Before RI-ISI implementation, there were 28 weld exams. Under RI-ISI, 12 welds are examined.

Code Category B-J

There are a total of 622 B-J welds in the ISI program. Before RI-ISI implementation, there were 157 weld exams. Under RI-ISI, 45 welds are examined.

In addition to ISI program welds, there are augmented IGSCC BWRVIP-75A program welds examined. For the IGSCC category A and D welds examined per BWRVIP-75A, there are six category B-F welds and 14 category B-J welds.

Use of the NRC-approved EPRI method for RI-ISI requires examining a minimum number of Class 1 welds ensuring the sample will always be greater than zero. Regardless of the size of the sample, the ISI program will continue to remain in full compliance with the requirements of 10 CFR 50.55a in effect at the beginning of each new 10-year inspection interval.

NRC Request: *RAI B.1.21-1*

Background:

The LRA states that aging management program B.1.21, "Masonry Wall Program," is consistent with the GALL report with one enhancement.

Issue:

For Element 4, "Detection of Aging Effect," the GALL report recommends "the most frequent inspection" for unreinforced masonry walls. However CNS does not discuss this in the basis document for this program.

Request:

Please discuss inspection frequency for the unreinforced masonry walls.

NPPD Response:

CNS does not have any unreinforced masonry walls within the scope of license renewal. Thus, inspection frequency for unreinforced masonry walls is not applicable for CNS in-scope masonry walls.

NRC Request: *RAI B.1.21-2*

Background:

For element 4, "Detection of Aging Effects," the GALL report recommends that the frequency of inspection is selected to ensure there is no loss of intended function between inspections.

Issue:

CNS states that inspections occur at least once every five years. There is no basis provided for this inspection frequency.

Request:

Please provide justification for the proposed inspection frequency

NPPD Response:

The inspection frequencies for the CNS structures are based on the guidance provided in NEI 96-03 "Guidelines for Monitoring the condition of Structures at Nuclear Power Plants," July 15, 1996, Revision D. The guideline is used in conjunction with NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" to establish the inspection frequency of the structures at CNS. The guidelines indicate the inspection frequency should be based on current structural condition, environment, age of structure and importance to public health and safety. The guidelines support an inspection frequency of at least once every five years for structures. When previously inaccessible areas become accessible, inspections of these areas are performed as appropriate.

The inspection frequencies of the structures at CNS are increased if significant degradation is noted based on operating experience. There have been no unusual events such as flooding or seismic activity to warrant additional examination. Operating experience justifies the established inspection frequency. The minimal degradation found during inspections has not been sufficient to challenge intended function of the structures. There has been no industry or site operating experience to warrant increasing the inspection frequency of the in-scope structures.

NRC Request: *RAI B.1.22-1*

Background:

The applicant's "Metal Enclosed Bus" AMP is a new program that inspects non-segregated metal-enclosed bus. In the GALL Report external inspection of the segregated metal-enclosed bus is covered by GALL AMP XI.S6, "Structures Monitoring Program."

The applicant proposed an exception to GALL AMP XI.E4 to merge the external inspection portion of the "Metal Enclosed Bus" program GALL AMP XI.S6 into LAR AMP B.1.22. The applicant identified the affected program elements of GALL AMP XI.E4 as "Parameters Monitored or Inspected" and "Detection of Aging Effects."

Issue:

LAR AMP B.1.22 program elements are not consistent with the program elements of GALL AMP XI.S6 except for the identification of inspection of external surfaces and elastomers (Parameters Monitored and Inspected and "Detection of Aging effects" program elements).

Request:

Please reconcile the differences between GALL AMP XI.S6 program elements and LAR AMP B.1.22 including operating experience.

NPPD Response:

CNS LRA Table 3.6.2-1 in rows for "Metal enclosed bus (non-segregated bus for SBO recovery) – enclosure assemblies" used notes E and 602. Note 602 states:

> The Metal-Enclosed Bus Inspection Program was enhanced to include the aging management program for these aging effects instead of using the Structures Monitoring Program."

The enclosure assembly materials "aluminum, steel, steel alloy" and "elastomers" correspond to NUREG-1801, Vol. 2 items VI.A-13 and VI.A-12 which reference NUREG-1801, Section XI.S6 as the recommended aging management program. For the external bus enclosure surfaces and elastomers, the following paragraphs provide the element by element comparison of LRA Section B.1.22 to NUREG-1801, Section XI.S6.

NUREG-1801, Section XI.S6, "Scope of Program"

"The applicant specifies the structure/aging effect combinations that are managed by its structures monitoring program."

LRA B.1.22 is the NUREG-1801, Section XI.E4 program, which specifies metal enclosed bus (MEB) as the affected structure. The exception identified in LRA B.1.22 provides for the management of the effects of aging for the external enclosure surfaces and elastomer components of MEBs at CNS.

NUREG-1801, Section XI.S6, "Preventive Action"

"No preventive actions are specified."

With respect to external MEB enclosure surfaces and elastomers, LRA B.1.22 is consistent with the preventive actions of NUREG-1801, Section XI.S6, as it includes no preventive actions.

NUREG-1801, Section XI.S6, "Parameters Monitored or Inspected"

"For each structure/aging effect combination, the specific parameters monitored or inspected are selected to ensure that aging degradation leading to loss of intended functions will be detected and the extent of degradation can be determined. Parameters monitored or inspected are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience. Although not required, ACI 349.3R-96 and ANSI/ASCE 11-90 provide an acceptable basis for selection of parameters to be monitored or inspected for concrete and steel structural elements and for steel liners, joints, coatings, and waterproofing membranes (if applicable). If necessary for managing settlement and erosion of porous concrete subfoundations, the continued functionality of a site dewatering system is to be monitored. The plant-specific structures monitoring program is to contain sufficient detail on parameters monitored or inspected to conclude that this program attribute is satisfied."

With respect to external MEB enclosure surfaces and elastomers, the specific parameters monitored or inspected under LRA B.1.22 are surface condition of the bus exterior surface including elastomers. The EPRI structural tools state that structural steel, steel alloys, aluminum exposed to indoor and outdoor air can potentially experience loss of material from corrosion, and that visual inspection of structural steel components can provide early indication of age-related degradation due to corrosion. In accordance with the MEB Program, the surface condition of MEB enclosure assembly external surfaces will be monitored as will the surface condition of visible surfaces of elastomer materials.

NUREG-1801, Section XI.S6, "Detection of Aging Effects"

"For each structure/aging effect combination, the inspection methods, inspection schedule, and inspector qualifications are selected to ensure that aging degradation will be detected and quantified before there is loss of intended functions. Inspection methods, inspection schedule, and inspector qualifications are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience. Although not required, ACI 349.3R-96 and ANSI/ASCE 11-90 provide an acceptable basis for addressing detection of aging effects. The plant-specific structures monitoring program is to contain sufficient detail on detection to conclude that this program attribute is satisfied."

With respect to external MEB enclosure surfaces and elastomers, the LRA Section B.1.22 inspection method and schedule are consistent with industry standards for structural inspections. The EPRI structural tools state that that visual inspection of structural steel components can indicate age-related degradation due to corrosion. Visual inspection is the same method as employed by the CNS Structures Monitoring Program for managing the effects of aging on external steel surfaces and elastomers. Qualified plant staff knowledgeable of the expected condition of MEB external surfaces and elastomers will perform the inspections of the MEB enclosure external surfaces and elastomers. Applicable aging effects are loss of material for MEB enclosures and change in material properties for elastomers.

NUREG-1801, Section XI.S6, "Monitoring and Trending"

"Regulatory Position 1.5, 'Monitoring of Structures,' in RG 1.160, Rev. 2, provides an acceptable basis for meeting the attribute. A structure is monitored in accordance with 10 CFR 50.65 (a)(2) provided there is no significant degradation of the structure. A structure is monitored in accordance with 10 CFR 50.65 (a)(1) if the extent of degradation is such that the structure may not meet its design basis or, if allowed to continue uncorrected until the next normally scheduled assessment, may not meet its design basis."

LRA B.1.22 addresses sections of MEB that are in the scope of the maintenance rule, 10 CFR 50.65. The monitoring and trending described in NUREG-1801, Section XI.S6 is consistent with requirements of the maintenance rule. The in-scope segments of metal enclosed bus are included in the Maintenance Rule program, so monitoring and trending will be conducted in accordance with the monitoring and trending described in NUREG-1801, Section XI.S6.

NUREG-1801, Section XI.S6, "Acceptance Criteria"

"For each structure/aging effect combination, the acceptance criteria are selected to ensure that the need for corrective actions will be identified before loss of intended functions. Acceptance criteria are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience. Although not required, ACI 349.3R-96 provides an acceptable basis for developing acceptance criteria for concrete structural elements, steel liners, joints, coatings, and waterproofing membranes. The plant-specific structures monitoring program is to contain sufficient detail on acceptance criteria to conclude that this program attribute is satisfied."

With respect to external MEB enclosure surfaces and elastomers, LRA B.1.22 specifies the following acceptance criteria to ensure that the need for corrective actions will be identified before loss of intended function.

The acceptance criterion for MEB enclosure assemblies will be no significant loss of material due to general corrosion that could lead to loss of intended function if left unmanaged. The acceptance criterion for MEB elastomers will be no cracks or gaps indicating significant change in material properties that could lead to loss of intended function if left unmanaged.

The acceptance criteria is essentially consistent with the standard established by the acceptance criteria of NUREG-1801, Section XI.E4 for internal surfaces of MEB enclosure assemblies, which specifies that no unacceptable indication of corrosion, cracks, foreign debris, excessive dust buildup or evidence of moisture intrusion is to exist.

NUREG-1801, Section XI.S6, "Corrective Action, Confirmation Process, and Administrative Controls"

"As discussed in the appendix to this report, the staff finds the requirements of 10 CFR 50, Appendix B, acceptable to address the corrective actions/confirmation process/administrative controls."

With respect to external MEB enclosure surfaces and elastomers, the LRA B.1.22 program is consistent with the corrective action, confirmation process and administrative controls attributes of NUREG-1801, Section XI.S6.

NUREG-1801, Section XI.S6, "Operating Experience"

"Although in many plants structures monitoring programs have only recently been implemented, plant maintenance has been ongoing since initial plant operation. A plant-specific program that includes the attributes described above will be an effective AMP for license renewal."

With respect to external MEB enclosure surfaces and elastomers, LRA B.1.22 is consistent with the operating experience of NUREG-1801, Section XI.S6 in that maintenance has been ongoing as necessary for MEB enclosures since initial plant operation.

Attachment 2 provides changes to LRA Section B.1.22 to address this RAI.

NRC Request: *RAI B.1.22-2*

Background:

The applicant's "Metal Enclosed Bus" AMP is a new program that inspects non-segregated metal-enclosed bus. In the GALL Report external inspection of the segregated metal-enclosed bus is covered by GALL AMP XI.S6, Structures Monitoring Program. Internal inspection is covered by GALL AMP XI.E4.

Applicant and staff walkdowns of in-scope segregated metal-enclosed bus duct between emergency station service transformer and 4.16 kV switchgear buses 1F and 1G and between *start-up station service transformer and 4.16 kV switch gear buses 1A and 1B noted a potential for degraded environmental conditions due to numerous birds around and on the segregated bus duct and the associated support structure. The applicant stated that condition report CR-CNS-2009-01815 had previously been generated to address the degraded environment but was pending resolution*

Issue:

The bus ducts experienced degraded conditions with a potential for long term degradation of the internal and external metal enclosed bus surfaces and elastomers. In addition, the staff is concerned that the observed degraded conditions may involve possible external and internal aging mechanisms not considered by the GALL Report.

Request:

Please provide condition report resolution. Provide justification that the resolution will control external and internal bus duct aging mechanisms due to bird infestation.

NPPD Response:

The referenced condition report documents an event-driven condition not associated with the effects of aging. This condition report was dispositioned in May 2009 with the assignment of an action to eliminate the bird population that is causing the issue in the main transformer yard. Once the birds are removed, the bus ducts will be cleaned.

CNS employs good maintenance practices by performing preventive maintenance on the non-segregated bus between the emergency station service transformer and the 4.16 kV switchgear (1F and 1G), and between the start-up station service transformer and 4.16 kV switch gear (1A and 1B). If the reliability of the off-site power path is negatively impacted, the maintenance rule would require appropriate corrective actions to correct the degradation.

As recognized by the CNS response to the referenced condition report, this issue was event-driven, not the result of long-term aging. The effects of the recent bird infestation will not result in a long-term change to the bus duct external environment that could cause degradation that will not be adequately managed by the proposed MEB Program. The potentially degraded environment caused by the bird excrement could provide a corrosive environment for aluminum, steel, and steel alloy. However, the aging effect from this environment is loss of material, which is addressed for license renewal by visual inspections performed in accordance with the MEB Program. Therefore, this operating experience would not impact the ability of the MEB Program to provide reasonable assurance that the intended functions would be maintained during the PEO.

NRC Request: *RAI B.1.24-1*

Background:

The applicant states in LRA Table 3.6.1 that the plant specific Non-EQ Bolted Connections program is an alternate to GALL report AMP XI.E6.

The Non-EQ Bolted Cable Connection AMP Scope of Program states that bolted cable connections in an existing preventive maintenance program are also excluded from this AMP.

Issue:

The basis for the exclusion of bolted cable connections included in an existing preventive maintenance program is not discussed in LAR AMP B.1.24. See also GALL AMP XI.E6 or ISG LR-ISG-2007-02 scope of program descriptions.

Request:

For bolted cable connections that are part of an existing preventive maintenance program connections provide the justification for the exclusion of these connections from LAR AMP B.1.24. The justification should discuss the differences in inspection or test methods and the surveillance interval with respect to GALL AMP XI.E6. The analysis should demonstrate that the preventive maintenance program satisfies the program elements of GALL AMP XI.E6 or as revised by ISG LR-ISG-2007-02.

NPPD Response:

The program described in the CNS LRA Section B.1.24 is a one-time inspection program. The purpose of this one-time inspection program is to verify there are no aging effects that require a periodic aging management program.

The basis for not including connections covered under an existing preventive maintenance program in the scope of this one-time inspection was that the preventive maintenance activities adequately confirmed the absence of applicable aging effects for those connections. The preventive maintenance program is not credited as an aging management program for non-EQ bolted cable connections, so there is no basis to demonstrate that the preventive maintenance program satisfies the program elements of NUREG-1801, XI.E6. In lieu of providing a detailed comparison of the preventive maintenance activities to the XI.E6 program, CNS elects to eliminate the exclusion of connections that are included in an existing preventive maintenance program. Attachment 2 provides a revision of LRA Section B.1.24 to remove this exclusion.

NRC Request: *RAI B.1.24-2*

Background:

The applicants' Non-EQ Bolted Cable Connection AMP description of Detection of Aging Effects follows either the GALL report AMP XI.E6 or ISG LR-ISG-2007-02 in that it specifies "other appropriate methods" for testing for LRA AMP B.1.24 program element, Detection of Aging Effects".

Issue:

The type and application of "other appropriate methods" is not clear as to whether it may include either qualitative or quantitative inspections. The staff concern is that a qualitative visual inspection does not support a one-time inspection program as proposed by ISG LR-ISG-2007-02. The type and application of "other appropriate methods" is not discussed by the applicant in LAR AMP B.1.24.

Request:

Establish whether CNS plans to employ qualitative visual inspections when insulated cable connections are not accessible for quantitative inspections such as contact resistance testing or thermography. Confirm that should visual inspections be employed, that they will be performed on a 5 year periodic basis with the first inspection prior to the period of extended operation.

NPPD Response:

NPPD has no plans to employ qualitative visual inspections during the program implementation, however, should visual inspections be employed, they will be performed on a 5-year periodic basis with the first inspection prior to the PEO. NPPD clarifies LRA Section B.1.24, Detection of Aging Effects, by replacing the phrase "other appropriate methods" with "other appropriate quantitative methods" (see Attachment 2).

NRC Request: *RAI B.1.25-1*

Background:

LRA AMP B.1.25 claimed that the program will be consistent with NUREG-1801, Section XI.E3, Inaccessible Medium-Voltage cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements. The Operating Experience element of the GALL Report states that minimizing exposure to moisture minimizes the potential for the development of water treeing. As additional operating experience is obtained, lessons learned can be used to adjust the program.

Issue:

Condition Report CR-CNS-2009-03078 documented results from a manhole inspection that were done for the license renewal aging management audit. As a result of this inspection significant water was found in the following manholes: MH7, MH8, and MH9. MH5. One manhole was not inspected since it is inside the main power transformer yard; however since it is part of the same duct, it is likely there is water inside that manhole as well.

Request:

(a) *Explain how CNS meets the scoping of the program applicability of the GALL AMP XI.E3, when cables are exposed to significant moisture over long period of time (i.e. more than a few days).*

(b) *Explain how this operating experience and planed corrective actions will be used to enhance the Non-EQ Inaccessible Medium-Voltage Cables and Connections Program to minimize the potential for the development of water treeing before operating unit enters into extended operating period.*

NPPD Response:

(a) NUREG-1801, Section XI.E3, "Scope of Program," states, "This program applies to inaccessible (e.g., in conduit or direct buried) medium-voltage cables within the scope of license renewal that are exposed to significant moisture simultaneously with significant voltage. Significant moisture is defined as periodic exposures to moisture that last more than a few days (e.g., cable in standing water). Periodic exposures to moisture that last less than a few days (i.e., normal rain and drain) are not significant."

As stated in NUREG-1801, the program described in Section XI.E3 applies to inaccessible medium-voltage cables within the scope of license renewal that are exposed to significant moisture over long periods of time (i.e., more than a few days). Therefore, this program applies specifically to CNS medium-voltage cables within the scope of license renewal that are potentially exposed to significant moisture over a long period of time (i.e., more than a few days).

(b) As required for all aging management programs, operating experience (plant and industry) is used to enhance program performance. The discovery of abnormal water level in manholes with electric cables would be resolved under the corrective action program. This resolution would address the need for further analysis of the condition or the need to change the dewatering or inspection frequency, so the program continues to manage the effects of aging for the PEO.

The inaccessible medium-voltage cables routed in manholes MH5, MH7, MH8, and MH9 between the 4.16 kV non-safety buses (1A and 1B) and the 161 kV control house power transformers (located in the 345 kV switchyard) were conservatively included in the scope of license renewal. These cables were listed in the scope of the inaccessible medium-voltage cable program in LRA Section B.1.25. During a loss of offsite power (LOOP) or a station blackout (SBO), the plant breakers that feed these cables are opened. Therefore, these cables are de-energized during a LOOP or SBO. Since these cables are de-energized, they do not perform a license renewal intended function during recovery from SBO.

As stated in USAR Section VIII-2.2.5: "Control and protection power for the 161 kV breakers is supplied by a 125 volt DC battery system in the 161 kV switchyard control house. Each 161 kV breaker is equipped with two independent trip coils fed from one power source." During normal and abnormal operation, the 161 kV switchyard breakers are controlled by the 125 VDC system in the 161 kV switchyard control house.

Therefore, the inaccessible medium-voltage cables routed in manholes MH5, MH7, MH8, and MH9 between the 4.16 kV non-safety buses (1A and 1B) and the 161 kV control house power transformers (located in the 345 kV switchyard) are not in scope of license renewal based on 10 CFR 54.4. Refer to Attachment 2 for changes to LRA Section B.1.25 resulting from this RAI.

<u>NRC Request</u>: *RAI B.1.27-1*

<u>Background:</u>

NUREG-1800, Table 3.6-2, FSAR Supplement for Aging Management of Electrical and Instrumentation and Control System identifies when the inspection will be implemented and how often the inspection will be performed.

<u>Issue:</u>

Cooper USAR supplement for AMP B.1.27 does not provide the frequency of inspection.

<u>Request:</u>

Provide the inspection frequency for AMP B.1.27 in the USAR.

<u>NPPD Response</u>:

NPPD has committed in the LRA to implement the B.1.27 Non-EQ Insulated Cables and Connections AMP prior to the PEO. This commitment requires implementing the program described in NUREG-1801, Section XI.E1, without exception. The NUREG-1801 program specifies visual inspection of accessible cables in an adverse localized environment at least once every 10 years, with the first inspection occurring prior to the PEO. Refer to Attachment 2 for revisions to the LRA USAR supplement to reflect this commitment.

NRC Request: *RAI B.1.29-1*

Background:

LRA Section B.1.29 states in part:

> *A representative sample will be selected from each unique material and environment combination covered under each of the activities. Each sample size will be based on Chapter 4 of EPRI document 107514, Age Related Degradation Inspection Method and Demonstration, which outlines a method to determine the number of inspections required for 90% confidence that 90% of the population does not experience degradation (90/90). Components with the same material-environment combinations at other facilities may be included in the sample.*

Issue:

The LRA did not provide the basis for the use of Chapter 4 of EPRI-107514. It is not clear how the inspection locations for the representative samples will be determined. It is not clear how components with the same material-environment combinations at other facilities will be included the sample.

Request:

(a) *Please justify the basis for using Chapter 4 of EPRI-107514 to determine the sample size of inspections for each unique material and environment combination.*

(b) *Please clarify what is meant by the term "representative sample" and explain in detail how the inspection locations for this "representative sample" will be selected.*

(c) *Please clarify what is meant by the statement "Components with the same material-environment combinations at other facilities may be included in the sample" and justify the use of this information in CNS's sample.*

NPPD Response:

(a) EPRI Report 107514, Age Related Degradation Inspection Method and Demonstration, describes methods used to inspect for age-related degradation during the PEO. As stated in this report, one key conservative feature of applying the 90% confidence level is the assumption that none of the inspected items will contain significant aging effects. Consequently, if a single item in the sample population has an aging effect of interest, the sample size is increased which will raise the confidence level to greater than 90%. In reality, the confidence level is greater than 90% since the inspection locations selected are the most susceptible to aging effects.

With a combination of proven statistical sampling, focus on susceptible locations, and a mechanism for increasing the sample size, the One-Time Inspection Program provides adequate assurance that the applicable components will continue to perform their intended function through the PEO.

As documented in the license renewal SER for James A. FitzPatrick Nuclear Power Plant (ADAMS Accession Number ML080250372), Section 3.0.3.1.6, One-Time Inspection, the staff has accepted use of this approach for sample size determination.

(b) Each group of components with the same material-environment combination is considered a separate population. A representative sample is defined as a specified number of individual items within a population. Locations are determined by susceptibility, accessibility, dose considerations, and operating experience. Where possible, low flow areas, drains, and low points are inspected since these locations are the most susceptible to aging effects.

(c) The One-Time Inspection Program is used to verify the effectiveness of water chemistry control, oil analysis, and diesel fuel monitoring programs which are based on industry guidelines. The material-environment combinations at CNS will be similar if not identical to those at other BWR facilities where the same industry guidelines are used. However, CNS plans to perform the required number of inspections to attain a 90/90 confidence level using only CNS components. Therefore, LRA Section B.1.29 is revised to remove the statement regarding use of other facility components with the same material-environmental combinations (see Attachment 2).

NRC Request: *RAI-B.1.30-1*

Background:

In the CNS LRA Section B.1.30, "One-Time Inspection - Small Bore Piping," the applicant stated that the program is consistent with the program elements in GALL AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small Bore Piping," which recommends one time volumetric inspection of small bore piping.

Issue:

No specific information was provided regarding examination of small-bore piping socket welds. During an onsite audit discussion, the applicant indicated that there is a plan to address the issue.

Request:

Please provide information on examination of small bore piping socket welds at CNS.

NPPD Response:

NUREG-1801, Section XI.M35 does not explicitly address socket welds. Because there is no accepted industry standard method for volumetric examination of socket welds, no such examinations are included in the CNS program. Small-bore Class 1 piping inspections at CNS are consistent with the staff-approved Inservice Inspection Program and meet ASME Code Section XI, Subsection IWB, small-bore piping requirements. The provisions of Section XI require surface examination of a sample of socket welds and VT-2 examination of all Class 1 socket welds each refueling outage. A review of plant operating experience at CNS identified no history of cracking in Class 1 small bore piping including socket welds.

NRC Request: *RAI B.1.34-1*

Background:

LRA Section B1.34, Selective Leaching, commits to consistency with the Gall Report which includes the AMP ten elements.

Issue:

The CNS Aging Management Program Evaluation Report Non-Class 1 Mechanical, CNS-RPT-07-LRD07, Revision 2, Section 3.5 quotes the GALL Report XI.M33 element wording and compares the CNS AMP to that. Description of the CNS AMP elements is not provided to evaluate the acceptability of the AMP.

Request:

For AMP B1.1.34, provide additional description of the basis, actions, support and specifics for the following elements:

A. *Scope of Program*
   1. *Clarify the scope of the AMP for hardness measurements where feasible or other accepted mechanical inspection techniques. Clarify what are considered other accepted mechanical inspection techniques.*
B. *Preventive Actions*
   1. *Clarify whether water chemistry monitoring will be utilized for any components on this AMP.*
C. *Parameters Monitored or Inspected*
   1. *Provide description of the parameters to be monitored or inspected, including the methods or techniques to be used. Identify specifics of hardness testing or other industry accepted mechanical inspection techniques.*
D. *Detection of Aging Effects*
   1. *Clarify how, and identify the frequency of, inspection or monitoring will adequately detect internal or external corrosion caused by selective leaching.*
E. *Acceptance Criteria*
   1. *Identify and provide details of acceptance criteria for hardness or other mechanical inspection technique and clarify what constitutes "identification of selective leaching," which would lead to further engineering evaluation and, if necessary a root cause analysis.*
F. *Operating Experience*
   1. *Confirm that CNS has had no operating experience that would indicate corrosion caused by selective leaching.*

<u>NPPD Response</u>:

<u>Request A.1</u>
Qualitative determination of selective leaching may be used in lieu of Brinell hardness testing for components within the scope of this program where hardness testing may not be feasible due to form and configuration. Other mechanical means such as scraping, chipping, or probing with a sharp tool provide an equally valid method to identify selective leaching.

<u>Request B.1</u>
Consistent with NUREG-1801 XI.M33 element 2, there are no preventive actions associated with the program. However, monitoring of water chemistry to control pH and concentrations of corrosive contaminants along with minimizing DO in treated water as part of the CNS water chemistry programs are effective in reducing selective leaching.

<u>Request C.1</u>
Selective leaching (graphitization) occurs in gray cast iron components when the iron is dissolved leaving behind a porous mass, consisting of graphite, voids and rust. Selective leaching (dezincification) in copper alloys occurs when zinc is dissolved in the liquid solution that comes in contact with the copper alloy component. When the zinc is removed, a weakened

and corroded structure is left behind. The use of visual inspection, Brinell hardness testing, and mechanical methods such as scraping, chipping, or probing with a sharp tool will identify the weakened or corroded structure by penetrating the surface of the component to some depth. Brinell hardness testing indicates possible selective leaching by measuring the size of a sample indentation created by a given force for a specific amount of time. The visual inspection will detect visible evidence of selective leaching while the mechanical methods detect a corroded component structure caused by selective leaching.

<u>Request D.1</u>
As indicated in NUREG-1801 XI.M33, the visual inspection and hardness measurement is to be a one-time inspection performed just before the PEO because selective leaching is a slow acting corrosion process. The one-time visual inspection prior to the PEO is performed on a selected set of components that are potentially susceptible to selective leaching. In addition to visual inspection, either Brinell hardness testing or examination by mechanical means such as scraping, chipping, or probing with a sharp tool will be performed to determine the presence of selective leaching.

<u>Request E.1</u>
The following describes the acceptance criteria for each inspection technique:

- Brinell hardness: no change in Brinell hardness from original design that indicates selective leaching.
- Mechanical means (scraping, chipping, probing with sharp tool): no unacceptable graphite structure removal.
- Visual examination: no unacceptable iron oxide buildup on gray cast iron with porosity or honeycomb-like structure underneath iron oxide.

If any of these acceptance criteria are not met, further engineering evaluation under the corrective action program would be initiated. The established corrective action program specifies when a root cause analysis is required.

<u>Request F.1</u>
The review of operating experience at CNS identified no occurrence of selective leaching.

<u>NRC Request</u>: *RAI B.1.35-1*

<u>Background:</u>

The applicant indicates that the proposed aging management program is consistent with the aging management recommended by the GALL Report. In the Preventive Actions section of the proposed aging management program, the applicant states that chemical treatment is not used for biological control. The applicant also states that macro biofouling organisms have not been *found at the plant. The operating experience reviewed (CR-CNS-2006-08450, CR-CNS-2007-00259, CR-CNS-2007-00559, CR-CNS-2007-00716, CR-CNS-2007-01192) and responses to staff questions indicate that both of these statements are no longer correct.*

Issue:

Plant conditions and operating practices appear to be in conflict with the proposed aging management program. Additionally, none of the operating experience reviewed indicated the details of the chemical treatments used (frequency, chemicals, dose rates, durations) or the effectiveness of those treatments. Appropriate actions relative to the mitigation of macro biofouling are different when clams are or are not present. The presence of clams at the plant may require a change in the proposed aging management program.

Request:

Please revise the proposed aging management program to reflect actual plant conditions and operations practices. Please provide information concerning the chemical treatments used (frequency, chemicals, dose rates, durations) and the effectiveness of those treatments. Please review the actions proposed by the aging management program in light of the presence of clams and revise the program as necessary.

NPPD Response:

Asiatic clams have been detected and as a result CNS performs periodic chemical treatment of the service water system for the control of mollusks (clams). Zebra mussels have not been detected at CNS. The chemical injection process is on a bi-annual basis after the spawning season for the mollusks. The chemical injected is a mixture of sodium hypochlorite and sodium bromide (sodium hypobromite) that is injected at a rate of 0.35 to 0.5 gallons/minute for a period of 14 to 21 days and until it is confirmed that 100% mollusk kill is obtained in a control bio-box. This treatment process began in 2008 and has been effective in the control of mollusks in the service water system. This is demonstrated by the absence of live mollusks during component inspections. The implementing procedures of the Service Water Integrity Program include the ongoing periodic chemical treatment of the service water system to control mollusks.

NRC Request: *RAI B.1.35-2*

Background:

In the Preventive Actions section of the proposed aging management program, the applicant states that "components are lined or coated only where necessary to protect the underlying metal surfaces". The aging management program, Open-Cycle Cooling Water System (XI.M20) recommended by the GALL Report states that all piping should be lined or coated. Plant *personnel indicate that internal linings or coatings are used on all buried piping and that all above ground piping is not internally coated. Operating experience reviewed indicates a significant number of failures of unlined piping.*

Issue:

The proposed aging management program appears to be inconsistent with the program recommended by the GALL Report in that some of the piping in use at the plant is not coated as recommended. Based on the operating experience reviewed, this piping appears to be failing at a greater rate than the piping which is coated as recommended by the GALL Report.

Request:

Please justify why the proposed aging management program is consistent with the GALL report.

NPPD Response:

The GALL Report states under Preventive Actions:

"The system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments."

The raw water environment at CNS is not aggressive based on operating experience which shows that the overall condition of the service water system is good with over 30 years of service. The application of coatings and linings is dependent on the materials selected and the environments to which they are exposed. At CNS, the open cycle cooling water systems were constructed of appropriate materials as defined by original specifications for the expected environment. Coatings or linings have been installed in specific areas where appropriate to ensure the continued ability of the systems to perform their intended functions.

Moreover, the parameters monitored/inspected section confirms that all components are not presumed to be coated or lined by stating "Cleanliness and material integrity of piping, components, heat exchangers, elastomers, and their internal linings or coatings **(when applicable)** [emphasis added] that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure heat transfer capabilities." The words "when applicable" clearly indicate that not all system components will be lined or coated.

For these reasons, the CNS program is identified as being consistent with NUREG-1801 and no exception is required.

NRC Request: *RAI B.1.35-3*

Background:

In the Parameters Monitored section of the proposed aging management program, the applicant states that the proposed aging management program ensures "cleanliness and material integrity". Alternatively, in the same section, the aging management program recommended by the GALL Report states that the system should be periodically "inspected, monitored or tested to ensure heat transfer capabilities".

Issue:

Ensuring cleanliness and material integrity differs from, and establishes a lower standard than, ensuring heat transfer capabilities.

Request:

Please modify the proposed aging management program to be consistent with the aging management program recommended by the GALL Report.

NPPD Response:

NUREG-1801 states that components "that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure heat transfer capabilities." The Parameters Monitored section of NUREG-1801 does not identify the parameters monitored during such inspection, monitoring and testing. As stated in the description of the program in Appendix B.1.35 and in the aging management program evaluation report, the program includes component inspections for cracking, erosion, corrosion, wear, and blockage and performance monitoring to verify the heat transfer capability of the safety-related heat exchangers cooled by service water. In accordance with the response to Generic Letter 89-13, CNS tests the RHR and reactor equipment cooling (REC) heat exchangers. Parameters calculated and monitored as part of these tests are fouling factor and heat transfer rate. For other components, cleanliness and material integrity are parameters monitored during periodic inspections to ensure heat transfer capabilities of the components as stated in NUREG-1801. If components are verified to be clean and intact, this confirms they will be able to perform their intended functions including heat transfer.

NRC Request: *RAI B.1.35-4*

Background:

In the Detection of Aging Effects section of the proposed aging management program, the applicant lists aging effects and mechanisms to be considered. This list does not include biofouling. The similar section of the aging management program recommended by the GALL report includes biofouling as an aging effect/mechanism.

Issue:

Biofouling is a critical issue in this aging management program which should be included in the Detection of Aging Effects section.

Request:

Please revise the proposed aging management program to include the detection of biofouling in the Detection of Aging Effects section.

NPPD Response:

Biofouling is not a separate aging effect identified in the LRA since biofouling is the accumulation of the of animal and plant life, including barnacles, mussels, clams, and algae. These macro-organisms attach themselves to solid surfaces during their growth cycle, and effectively seal off a small part of the surface from its normal environment. Biofouling typically occurs within the first several days of exposure to a raw water environment regardless of the age of the affected components. In terms of corrosion effects, the long term impact of biofouling is creation of an environment that is potentially more aggressive leading to the aging effect of loss of material. As a result, biofouling is not listed as a unique aging effect that is managed by the aging management program.

However, the program description includes component inspections for blockage and performance monitoring to verify the heat transfer capability of the safety-related heat exchangers cooled by service water. The scope section also states that this program addresses loss of material and fouling due to micro- or macro-organisms and various corrosion mechanisms. The program preventive actions section states that the intake structure basin is periodically inspected for biological fouling organisms. Parameters monitored or inspected section states that the program includes inspections, monitoring, and testing to ensure cleanliness and that the program ensures removal of accumulations of biofouling agents, corrosion products, and silt that could adversely affect performance. These statements clearly indicate that detection of biological fouling is part of the program.

NRC Request: *RAI B.1.35-5*

Background:

Generic Letter 89-13 establishes a variety of inspections and tests required to adequately maintain a service water system. Included within these requirements are testing intervals or frequencies.

Issue:

While many these testing intervals are implicitly acknowledged by the applicant in supporting documents, explicit acknowledgement of some of the testing intervals appears to be lacking in documentation which can be readily connected to this aging management program.

Request:

Please identify all testing and inspection requirements imposed by Generic Letter 89-13. Please provide all testing intervals being utilized by the plant and demonstrate that these intervals are consistent with the requirements of Generic Letter 89-13.

NPPD Response:

GL 89-13 required the following actions in regards to testing and inspections:

Action I: Implement and maintain an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage as a result of biofouling.

Action II: Conduct a test program to verify the heat transfer capability of all safety related heat exchangers cooled by service water. The total test program should consist of an initial test program and a periodic retest program. The initial frequency of testing should be at least once each fuel cycle, but after three tests, Licensees should determine the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests; or in lieu of testing, performance of regular preventive maintenance. The minimum test/inspection frequency is 5 years. Evaluation of test/inspection history is utilized to determine actual frequencies.

Action III: Ensure by establishing a routine inspection and maintenance program for open-cycle service water system piping and components that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of the safety related system supplied by service water.

These actions are implemented by the following testing and inspection activities:

1	The intake structure inspection includes examination of the basin for silt, debris, biological fouling organisms and deterioration (including corrosion) and frequent monitoring of silt levels. The deterioration inspection is performed using divers or dewatering the bay. River sediment is sampled annually to determine if Asiatic clams are present. Inspection is performed every 18 months or refueling outage based on availability.
2	CNS surveillance program provides for flow tests once per operating cycle to ensure the service water system and the associated required safety related components meet or exceed post-LOCA design flow requirements.
3	Pump performance is monitored and trended quarterly to detect trends adverse to system performance.
4	Heat exchangers when opened are inspected for indications of Corbicula and other macroscopic biological fouling organisms as well as corrosion and coating degradation. The heat exchanger inspection and cleaning frequency is as follows: RHR at least once per 48 months, REC once per 12 months, Diesel lube oil and jacket water once per 156 weeks and Diesel intercoolers once per cycle.
5	Heat transfer capability of the RHR and REC heat exchangers are verified. One RHR heat exchanger is tested each operating cycle on an alternating basis. The REC heat exchangers are tested at least quarterly.
6	Applicable heat exchanger performance evaluation procedures require trending to ensure flow blockage or excessive fouling accumulation does not prevent performance of safety related functions.
7	Selected wall thickness testing (UT) of service water and RHR service water booster system piping, fittings and valves are included in the Erosion and Corrosion Program. On average 46 UT exams are performed each cycle.
8	Heat exchanger and pump maintenance procedures provide documentation with regard to extent and results of the inspection including inspection for corrosion, erosion, protective coating failure, silting, and biofouling as appropriate.

The implementation of these testing and inspection activities at the specified intervals in the table is consistent with Actions I, II, and III of GL 89-13 as stated above since the testing and inspections meet the minimum test/inspection frequency of five years. In addition, a review of operating experience for the Service Water Integrity Program, including GL 89-13 requirements, has demonstrated that these activities performed at the specified intervals have been effective at managing aging effects, and ensures that the performance of the service water system intended functions has not been and will not be adversely affected. These testing and inspection activities at the specified frequencies have been previously approved by the NRC staff as acceptable. Ongoing inspections and program assessments have also confirmed and will continue to confirm the effectiveness of the program.

<u>NRC Request</u>: *RAI B.1.36-1*

<u>Background:</u>

In the GALL Report AMP XI.S6, program element 3 and 4 states that for each structures/aging effect combination, the specific parameters monitored or inspected are selected to ensure that the aging degradation leading to loss of intended function will be detected and quantified before there is loss of intended function.

<u>Issue:</u>

As a results from a field walk-down with the applicant's technical staff on April 21, 2009, the staff noticed significant leaching deposits in the torus room between torus support # 15 and # 16 on and around RHR and HPCI piping penetrations and base of pipe support RH-H16; leaching deposits and water stains in the basement floor between torus support # 7 and 8, # 12 and 13, and at # 11; the nuts for several cast-in place anchors for the torus box beam assembly (main column support) have only couple of threads engaged. As a results, the applicant initiated CR-CNS-2009-03188, CR-CNS-2009-03185, and CR-CNS-2009-3194 respectively. For the intake structures: Division 1 and Division 2 of service water pump (E bay) where the staff noticed rusty/spalling on Division 1 of SW discharge strainer concrete pedestal, the applicant also initiated CR-CNS-2009-03204.

<u>Request:</u>

Please describe the an aging effects included in the Structures Monitoring Program and how they are managed to ensure that there is no loss of intended function through the PEO.

<u>NPPD Response</u>:

The LRA in section 3.5 identifies aging effects managed by the Structures Monitoring Program (SMP) for specific structures, components or commodities. The CNS SMP manages those aging effects through visual inspections of parameters in accordance with 10 CFR 50.65 (Maintenance Rule) as addressed in Regulatory Guide 1.160 and NUMARC 93-01. The CNS SMP is controlled by site procedures which specifically employ the inspection guidance of NEI 96-03, "Industry Guideline for Monitoring the Condition of Structures at Nuclear Power Plants."

The SMP manages the effects of aging related to the specific observations noted in the "Issue" section of this RAI through visual inspections of parameters. A lack of thread engagement on nuts is due to construction or maintenance practices and is not an effect of aging. The assessments of the observed conditions, performed under the site corrective action program, indicate they do not represent a threat to the ability of affected structures to perform their intended functions.

Aging effects on concrete related to the observations identified in this RAI are loss of material, cracking and change in material properties. The parameter visually monitored to manage these aging effects is the condition of exposed concrete surfaces. Acceptance criteria include the absence of spalling and the absence of leaching. Failure to meet the acceptance criteria is cause for documenting the condition in the site corrective action program for further evaluation.

The deposits on the floor between torus supports were evaluated under the CNS corrective action program. The evaluation indicates that the deposits do not represent a threat to structural integrity of the reactor building floor slab or walls, piping, or pipe supports. Future inspections under the Structures Monitoring Program will ensure the structure continues to remain capable of performing its intended function.

Spalling of the service water discharge strainer concrete pedestal concrete was evaluated under the CNS corrective action program. The evaluation indicates the degradation of the concrete pedestal and associated angle iron is minor and does not challenge the structural integrity of the pedestal Future inspections under the SMP will ensure the structure continues to remain capable of performing its intended function.

Continued implementation of the SMP with the enhancements identified in LRA, B.1.36, assures the effects of aging are managed so that structures and commodities crediting this program can perform their intended function consistent with the current licensing basis through the PEO.

NRC Request: *RAI B.1.36-2*

Background:

In the GALL Report AMP XI.S6, "acceptance criteria" program element stated that acceptance criteria are to be commensurate with industry codes, standards and guidelines, and are to also consider industry and plant-specific operating experience.

CNS's program basis document procedure LRD08 AMP 3.3 for Structures Monitoring Program, the applicant also stated that ".....Industry and plant-specific operating experience was also considered" (Ref. Section 7.3, 7.4 and 14.4, Administrative Procedure 0.27.1).

Issue:

There is no information provided as how industry and plant-specific operating experience considered.

Request:

Please provide how industry and plant-specific operating experience is included in the Structures Monitoring Program to be consistent with the GALL Report recommendations.

NPPD Response:

In compliance with the requirements of 10 CFR 50.65(a)(3), the CNS site operating experience process ensures industry and plant-specific operating experience are reviewed and evaluated by appropriate personnel for applicability and potential effect on plant operations and programs to ensure effectiveness of the maintenance activities. The CNS SMP, which is controlled by site procedure, specifically requires use of the operating experience process to ensure impact or potential impacts are identified, evaluated, and incorporated into the program, as appropriate. This requirement is identified in the CNS administrative procedure that governs the SMP, which specifies reviewing, screening and applying lessons learned to the SMP to prevent or minimize the possibility and significance of a similar event and ensuring condition reports are generated per the corrective action procedures when adverse conditions are identified during review or evaluation of an operating experience item.

NRC Request: *RAI B.1.36-3*

Background:

As stated in LRA the Aging Management Program B.1.36 "Structures Monitoring Program," is consistent with the GALL report with enhancements.

Issue:

For element 5, "Monitoring and Trending," GALL recommends Regulatory Position 1.5 in Regulatory Guide 1.160, Rev 2, as an acceptable basis for meeting the element. However, the CNS program basis document does not discuss it for this element.

Request:

Please discuss whether CNS uses the above Regulatory Position for its Structures Monitoring Program. If not please justify why the CNS program is consistent with GALL.

NPPD Response:

The CNS SMP is controlled by site procedures which follow the recommendations of Regulatory Guide 1.160, including Regulatory Position 1.5, for monitoring and trending structure condition. Consistent with Regulatory Position 1.5, the program provides for periodically monitoring CNS structures in accordance with 10 CFR 50.65(a)(2) provided there is no significant degradation of the structure. If established criteria as specified in maintenance rule scoping documents are exceeded, the affected system is monitored in accordance with a 10 CFR 50.65(a)(1) action plan. The program includes requirements for performing baseline inspection, periodic inspections, appropriate frequency of the inspections commensurate with the safety significance of the structure, evaluation of degradation, and trending results. The program also includes additional degradation-specific monitoring and increased frequency for structures monitored in accordance with 10 CFR 50.65(a)(1).

NRC Request: *RAI B.1.36-4*

Background:

For element 4, "Detection of Aging Effects," the GALL report recommends that the inspection schedule is selected to ensure that aging degradation will be detected and quantified before there is loss of intended functions.

Issue:

CNS states that inspections of accessible plant structures are performed at five-year intervals. There is no basis provided for this inspection frequency.

Request:

Please justify the proposed inspection frequency. In addition, please discuss and justify the inspection frequency for inaccessible areas.

NPPD Response:

The inspection frequencies for the CNS structures are based on guidance provided in NEI 96-03 "Guidelines for Monitoring the condition of Structures at Nuclear Power Plants," July 15, 1996, Revision D. The guideline is used in conjunction with NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," to establish the inspection frequency of the structures at CNS. The guidelines indicate the inspection frequency should be based on current structural condition, environment, age of structure and importance to public health and safety. The guidelines support an inspection frequency of at least once every five years for structures. When previously inaccessible areas become accessible, inspections of these areas are performed as appropriate. The minimal degradation found during inspections of accessible structures indicates no need to perform additional inspections on inaccessible structures that are the same materials exposed to the same environments.

The inspection frequencies of the structures at CNS are increased if significant degradation is noted. There have been no unusual events such as flooding or seismic activity to warrant additional examination. Operating experience justifies the established inspection frequency. Degradation found during inspections has not been sufficient to challenge intended function of the structures. There has been no industry or site operating experience to warrant increasing the inspection frequency of the in-scope structures.

NRC Request: *RAI B.1.37-1*

Background:

LRA AMP B.1.37, "Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel," manages the reduction of fracture toughness due to thermal aging and reduction of fracture toughness due to radiation embrittlement on the intended function of CASS components. The AMP includes screening criteria to identify susceptible components and for each potentially susceptible component aging management is accomplished by either a supplemental examination or component-specific evaluation of susceptibility. The applicant claims that AMP B.1.37 is consistent with GALL AMP XI.M13.

Issue:

The GALL report states, "The screening criteria for susceptibility to thermal aging embrittlement are not applicable to niobium-containing steels; such steels require evaluation on a case-by-case basis." The staff's review of AMP B.1.37 showed that the applicant did not discuss whether any CASS materials were niobium bearing.

Request:

Please identify if niobium-bearing CASS material is used for any vessel internal components. If so, please provide a program for staff evaluation.

NPPD Response:

The Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new program that will be implemented prior to the PEO. Consistent with the statement on page six of the Grimes letter[2], the CASS components are not expected to contain niobium. The GALL program statement regarding niobium states that the screening criteria are not applicable; not that the program is not applicable to niobium bearing materials. If niobium is found to be a constituent of any CASS component material, the component will be

[2] Letter from Christopher I. Grimes, U.S. Nuclear Regulatory Commission, License Renewal and Standardization Branch, to Douglas J. Walters, Nuclear Energy Institute, License Renewal Issue No. 98-0030, *Thermal Aging Embrittlement of Cast Stainless Steel Components*, May 19, 2000, (ADAMS Accession No. ML003717179)

considered susceptible to thermal aging embrittlement, without the application of the screening criteria. Consistent with any other component found susceptible to thermal aging embrittlement, such components will be evaluated to determine they are not susceptible to reduction of fracture toughness or if susceptible, they will be examined via a supplemental inspection in accordance with NUREG-1801, Section XI.M13 recommendations.

NRC Request: *RAI-B.1.37-2*

Background:

LRA AMP B.1.37, "Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel," manages the reduction of fracture toughness due to thermal aging and reduction of fracture toughness due to radiation embrittlement on the intended function of CASS components. The AMP includes screening criteria to identify susceptible components and for each potentially susceptible component aging management is accomplished by either a supplemental examination or component-specific evaluation of susceptibility. The applicant claims that AMP B.1.37 is consistent with GALL AMP XI.M13.

Issue:

The GALL report states, "Flaw tolerance evaluation for components with ferrite content up to 25% is performed according to the principles associated with IWB-3640 procedures for submerged arc welds (SAW), disregarding the Code restriction of 20% ferrite in IWB-3641(b)(1). ... Flaw evaluation of CASS components with 25% ferrite is performed on a case-by-case basis by using fracture toughness data provided by the applicant." In CNS-RPT-07-LRD02 Revision 1, the applicant stated: "Flaw evaluation for CASS components with >25% ferrite content will be developed on a case-by-case basis using fracture toughness data. The applicable BWRVIP guidelines will be used for flaw evaluation of internal components for which IWB-3500 and IWB-3640 are not applicable." It is not clear what the applicant means by "applicable BWRVIP guidelines" because none of the BWRVIP documents address the reduction of fracture toughness due to thermal aging embrittlement and radiation embrittlement.

Request:

Please clarify what is meant by applicable BWRVIP guidelines will be used for components for which IWB-3500 and IWB-3640 are not applicable. Unless it can be confirmed that there is no CASS with >25% ferrite, please provide a flaw evaluation methodology for CASS internal components with >25% ferrite for staff review.

NPPD Response:

The BWRVIP documents provide guidance for flaw evaluations of various non-Code vessel internals components. Although the BWRVIP documents do not address the reduction of fracture toughness due to thermal aging and neutron embrittlement, guidance developed through industry initiatives would be disseminated by and included in the BWRVIP documents. Since the Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel Program is a new program, the specific composition of CASS materials and the casting methods used for components in the reactor vessel internals will be established as part of the program implementation prior to the PEO. During the implementation process, these components will be screened to determine which components are potentially susceptible to reduction of fracture toughness on the basis of casting method, molybdenum content, and ferrite content. Potentially susceptible components will then be either evaluated to determine they are not susceptible to reduction of fracture toughness or scheduled for examination via a supplemental inspection.

If components with >25% ferrite are identified, found to be potentially susceptible to reduction of fracture toughness, and scheduled for a supplemental inspection, CNS will determine the appropriate methodology for flaw evaluation in accordance with available BWRVIP guidance.

NRC Request: *RAI B.1.38-1*

Background:

LRA Section B.1.38, "Water Chemistry Control – Auxiliary Systems" description states in part: "Program activities include sampling and analysis of water in auxiliary condensate drain system components, auxiliary steam system components, and heating and ventilation system components to minimize component exposure to aggressive environments."

Under "3. Parameters Monitored/Inspected," it states in part: "In accordance with industry recommendations, auxiliary condensate drain system and auxiliary steam system water parameters monitored are pH, conductivity, phosphate, sulfite, and iron." Furthermore, it also states that "In accordance with industry recommendations, heating and ventilation systems parameter monitored is sodium nitrite ($NaNO_2$)."

Issues:

- *It is not clear to the reviewer the reason(s) why a plant-specific water chemistry control program is necessary for the auxiliary systems.*
- *The LRA did not include a reference to the aforementioned industry recommendations.*

<u>Request</u>:

Please provide:

(a) *a comparison between the plant-specific water chemistry control program and the closed-cycle cooling water system and the water chemistry program in NUREG-1801 volume 2 and a justification as to why the GALL programs are not suitable for the auxiliary systems*

(b) *Any applicable reference(s) to the industry recommendations*

<u>NPPD Response</u>:

(a) The design of the auxiliary steam system electric boiler requires a high level of water conductivity to propagate the electric arc generated by the boiler coil. This renders the system unsuitable for control under the EPRI guidelines for chemistry control of closed cooling water referenced by the GALL programs. Similarly, the chemistry requirements for the chilled water portion of the heating and ventilation system reflect the specific design of the components involved such that EPRI requirements cannot be met.

Industry standards, such as manufacturer's recommendations, are used as the basis for "parameters to be monitored" and "acceptance criteria." In the license renewal SER for FitzPatrick (ADAMS Accession Number ML080250372), the NRC staff determined that this basis is acceptable since it considers information from appropriate sources that will provide reasonable assurance that appropriate acceptance criteria are used. Industry references for water chemistry control of auxiliary systems at CNS include recommendations from the auxiliary steam system electric boiler manufacturer and a water treatment company.

The NRC staff, as documented in Section 3.0.3.3.5 of the license renewal SER for FitzPatrick, has accepted the position that the activities included in a plant-specific program for water chemistry control of auxiliary systems will adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the CLB for the PEO.

(b) Vendor recommendations are discussed in response to part (a).

NRC Request: *RAI B.1.39-1*

Background:

LRA Section B.1.39, "Water Chemistry Control-BWR," references CNS Operations Manual Chemistry Procedures 8.3 and 8.3VIP requirements for water chemistry parameters for three operating conditions, namely cold shutdown, startup/hot standby, and power operation. For startup/hot standby conditions, Procedure 8.3 specifies that an Action Level 3 condition is reached when the reactor water conductivity exceeds 2.0 µmho/cm. This is consistent with and, in fact, more conservative than the corresponding value of 5.0 µmho/cm given in EPRI Report 1008192 (BWRVIP-130), which supersedes EPRI Report TR-103515 (BWRVIP-29) and forms the basis for the GALL BWR water chemistry requirements. The applicant's Procedure 8.3 also specifies that an alternative Action Level 3 value of 20 µmho/cm applies during noble metal application, but does not indicate a time duration for this increased conductivity transient.

Issue:

Footnote b to Table 6.3.2 of BWRVIP-130 likewise allows for unspecified increased conductivity above its stated Action Level 2 value of 1.0 µmho/cm during the application of noble metals, but it specifies a time duration of approximately 48 hours for this conductivity transient.

Request:

Please define the time duration for the conductivity transient following noble metal application for which the applicant's Action Level 3 value of 20 µmho/cm applies.

NPPD Response:

The time duration for the conductivity transient following noble metal application at CNS is defined in TRM TLCO 3.4.1 as up to 48 hours of noble metal injection, followed by up to 24 hours for restoration to acceptable chemistry limits.

NRC Request: *RAI B.1.39-2*

Background:

For power operating conditions, CNS Operations Manual Chemistry Procedure 8.3 specifies that an Action Level 1 condition is reached when the reactor water conductivity reaches or exceeds 0.18 µmho/cm, with certain exceptions noted for transient conditions. This is more conservative than the corresponding value of 0.30 µmho/cm given in EPRI BWRVIP-130 (BWRVIP-130). The applicant's Procedure 8.3 also allows a higher limit value of 0.5 µmho/cm when the conductivity is increased "due to soluble iron concentration."

Issue:

No exception is noted in EPRI BWRVIP-130 for higher conductivity limits associated with soluble iron.

Request:

Please provide a justification for the higher conductivity limit and a discussion of the procedure for determining the relative contributions of soluble iron versus more aggressive species to the total conductivity.

NPPD Response:

Justification for the higher conductivity limit associated with soluble iron

BWRVIP-130 contains a discussion of soluble zinc and iron affecting conductivity as a result of starting and stopping hydrogen injection. Initiation of hydrogen injection results in the reactor water transitioning from an oxidizing to reducing environment. That transition increases the solubility of iron, and therefore the iron concentration rises. However, iron is not an aggressive ion species for stress corrosion cracking. In addition, zinc is added to the reactor water through the depleted zinc oxide process.

The ions of particular interest for loss of material and for stress corrosion cracking are the strong anions, particularly sulfate and chloride ions. Since the loss of material and cracking phenomena described in the BWRVIP are not significantly influenced by zinc and iron cations, correcting the conductivity for these cations is appropriate to determine whether the environment could actually accelerate the crack growth rate of susceptible materials.

The predecessor of the BWRVIP-130 guidance for BWR water chemistry was BWRVIP-79 "BWR Water Chemistry Guidelines – 2000 Revision" (TR-103515-R2). Table 4-5b on page 4-11 of BWRVIP-79 provides a conductivity limit for reactor water when greater than 10% power for HWC and HWC+NMCA plants of >0.30 μmho/cm. The applicable footnote (g) states "For plants starting up with NMCA, contributions due to soluble iron may be subtracted from the measured conductivity to evaluate conformance to action levels."

Discussion of the procedure for determining the relative contributions of soluble iron versus more aggressive species to the total conductivity

The following definitions are used in this discussion:

Calculated Conductivity: The conductivity calculated from the measured cations and anions.

Corrected Conductivity: The conductivity calculated with the same set of ions used for the calculated conductivity but with the concentrations of iron (Fe2+) and zinc (Zn2+) forced to zero.

The reactor water AL1 conductivity value at CNS is 0.5 μmho/cm based on calculated conductivity. However, as reactor water conductivity results are entered into the chemistry data management system, an AL1 violation is identified for any reading ≥ 0.18 μmho/cm, triggering an investigation to determine cause. Conductivity due to all reactor water ions, including soluble iron, is then entered into a conductivity balance calculator. The contribution from soluble iron is then subtracted out to determine the corrected conductivity.

- If corrected conductivity is below 0.3 μmho/cm, then no AL1 limit violation is recorded. The chemistry technicians are informed of the elevated soluble iron in reactor water. Technicians use the higher AL1 of 0.5 μmho/cm for the calculated conductivity until the soluble iron concentration in reactor water decreases.

- If corrected conductivity is greater than 0.3 μmho/cm, then the actions for exceeding an AL1 value are taken.

NRC Request: *RAI B.1.40-1*

Background:

In LRA Section B.1.40, "Water Chemistry Control-Closed Cooling Water," the applicant proposed an exception to GALL program elements Parameters Monitored/Inspected, Detection of Aging Effects, Monitoring and Trending, and Acceptance Criteria, that excludes performance and functional testing of closed cooling water systems from the program. This proposed exclusion is based upon EPRI Report 1007820 ("Closed Cooling Water Chemistry Guideline, Revision 1"), which supersedes EPRI Report TR-107396 and forms the basis for the GALL closed cooling water chemistry requirements. In this report, the applicant cites Section 8.4.4 stating that "performance monitoring is typically part of the engineering program." The applicant infers from this statement that performance monitoring can therefore be excluded from the closed cooling water chemistry program.

Issue:

If performance monitoring and functional testing of closed water system components such as heat exchangers is not included under the present program, it is not clear whether, how, and under what AMP this evaluation will be carried out.

Request:

Please indicate how and under what AMP the monitoring and functional testing of the closed water system components is to be carried out. If monitoring and functional testing is not carried out, please justify why it is not considered necessary.

NPPD Response:

While NUREG-1801, Section XI.M21, Closed-Cycle Cooling Water System, endorses EPRI report TR-107396 for performance and functional testing guidance, EPRI report TR-107396 does not recommend that equipment performance and functional testing be part of a water chemistry control program. This is appropriate since monitoring pump performance parameters is of little value in managing effects of aging on long-lived, passive closed cooling water system components. Rather, EPRI report TR-107396 states in section 5.7 (Section 8.4 in EPRI report 1007820) that performance monitoring is typically part of an engineering program, which would not be part of a water chemistry program. In most cases, functional and performance testing verifies that component active functions can be accomplished and as such would be governed by the maintenance rule (10 CFR 50.65). For example, loss of material cannot be detected by system performance testing. Passive intended functions of pumps, heat exchangers and other components will be adequately managed by the Water Chemistry Control-Closed Cooling Water and One-Time Inspection programs through monitoring and control of water chemistry parameters and verification of the absence of aging effects. As documented in Section 3.0.3.2.16 of the preliminary license renewal SER for Indian Point (ADAMS Accession Number ML090150571), the NRC Staff has accepted the position that the activities included in the Water Chemistry Control-Closed Cooling Water Program are adequate to manage the aging effects for which the program is credited without including performance and functional testing.

NRC Request: *RAI B.1.40-2*

Background:

LRA Section B.1.40, "Water Chemistry Control-Closed Cooling Water," references CNS Operations Manual Chemistry Procedure 8.3 requirements for water chemistry parameters for the closed water system. In particular, Procedure 8.3 Sections 8.1 and 8.2 specify allowable limits on conductivity, pH, and concentrations of selected chemical species for the Turbine Equipment Cooling (TEC), Reactor Equipment Cooling (REC), and diesel generator jacket cooling water systems. These limits define chemistry warning limit (CWL) and selected Action Levels 1 and 2 conditions.

Issue:

In comparing these limits to the corresponding values in EPRI Report 1007820 Tables 5.1 and 5.7, it is noted that they are in compliance in all cases where the applicant provides values. However, a number of EPRI 1007820 limit values are omitted from the applicant's Procedure 8.3 tables. For the TEC and REC water systems, Procedure 8.3 does not specify Action Level 2 limits for conductivity, chloride, or sulfate, levels, nor does it state fluoride levels for either Action Levels 1 and 2. For the diesel generator jacket water chemistry, Procedure 8.3 does not specify Action Level 2 limits for nitrite concentrations, nor does it mentions limits on chlorides and fluorides.

Request:

Please clarify the reason for these apparent inconsistencies between Procedure 8.3 and EPRI Report 1007820 Tables 5.1 and 5.7.

NPPD Response:

During the onsite audit of aging management programs, the NRC audit team reviewed the revision of the chemistry procedure for "control parameters and limits" (Chemistry Procedure 8.3) that was current when the LRA was prepared. The reviewed procedure included Action Level 2 (AL2) limits for the REC and turbine equipment cooling (TEC) systems for conductivity, chloride and sulfate. However, the procedure did not include all parameters recommended by EPRI Report 1007820. Parameters missing were pH AL2 limits for TEC, REC, and the diesel generator jacket water (DGJW) systems, as well as AL2 limits for nitrite and chloride for the DGJW system. Site chemistry control procedures have been revised to incorporate these limits.

It is not necessary to analyze fluoride for the REC and TEC water systems since they do not experience temperatures above 150 °F, as discussed in Note 4 to Table 5-1 of EPRI Report 1007820, Closed Cooling Water Guidelines. As a result fluoride limits are not included in the site chemistry procedures for the REC and TEC water systems.

The only source of fluoride contamination for the DGJW system is the Missouri River, which is the heat sink for the DGJW heat exchanger. Chemical analysis of the Missouri River has been performed multiple times over 35 years of plant operation. Fluoride concentration levels in river water have ranged between 250 ppb and 750 ppb with an average of approximately 500 ppb (0.5 ppm). Thus if the DGJW system was completely saturated with Missouri River water, the fluoride concentration would not exceed 1 ppm. EPRI TR-1007820 Table 5-1 lists the limit for fluoride as < 10 ppm. Therefore, since there is no credible source for fluoride to reach 10 ppm in the DGJW, analysis for fluoride provides no benefit for the reduction or prevention of corrosion of DGJW components. As a result fluoride limits are not included in the site chemistry procedures for the DGJW system.

NRC Request: *RAI B.1.40.3*

Background:

The applicant's condition report CNS-CR-2004-3119 describes an occurrence in which the dissolved oxygen level in the Turbine Equipment Cooling (TEC) and Reactor Equipment Cooling (REC) water systems averaged 6 ppm (saturation) for at least one year and probably longer. This compares with a maximum level of 50 ppb specified in the applicants Procedure 8.3, Rev. 51 and 200 ppb specified in EPRI Report 1007820 ("Closed Cooling Water Chemistry Guideline, Revision 1"), which supersedes EPRI Report TR-107396 and forms the basis for the GALL closed cooling water chemistry requirements. The condition report stated that the cause of the high oxygen level was under investigation, and it noted that oxygen monitoring in this system had been suspended from July of 2003 through July 7, 2004, the date of the report. Another dissolved oxygen excursion in the REC cooling water system was reported in 2006 (CNS-SR-2006-6741 CA-01), but the magnitude and duration of this excursion were not described.

Issue:

CNS-CR-2004-3119 and CNS-SR-2006-6741 CA-01 do not describe the long-term resolution of this problem, nor does they discuss possible degradation of the TEC and REC water systems.

Request:

Please describe the long-term resolution of this dissolved oxygen control problem and provide a discussion of any resulting potential degradation of the TEC and REC water systems. In addition, please discuss operating experience since these occurrences.

NPPD Response:

In response to the high DO oxygen levels in 2004, new deaeration skids were placed into service for the TEC and REC systems in July 2006. However, DO levels remained high in both systems until late August 2006. Troubleshooting to determine the cause of this condition found that the surge tank recirculation valves on the TEC and REC systems were open. This had created a flowpath by which oxygen-saturated water continuously entered the system, resulting in high DO concentrations. The effect of closing the recirculation valve on the DO levels was as follows:

REC

Within two weeks after closing the recirculation valves, DO levels in the REC system dropped significantly.

- 940 ppb on September 5, 2006
- 171 ppb on September 12, 2006
- 0 ppb on September 20, 2006

Maximum DO level in the REC system since this time has been 40 ppb, within the desired range of 30 ppb to 100 ppb.

TEC

DO levels in the TEC system dropped more slowly after closing the surge tank recirculation valve, due to system leakage and the automated makeup of oxygenated water.

- < 100 ppb by October 2006
- In April 2009, DO level rose to 150 ppb due to an increase in the system feed and bleed rate. This was brought below 100 ppb through a reduction in the feed and bleed rate.

DO level in the TEC system since this time has fluctuated above and below 50 ppb, but remained within the desired range of 30 ppb to 100 ppb.

Discussion of effects of high oxygen concentration on the TEC and REC systems

Due to the low temperatures and low flow rates, the predominant effect of high DO levels in the TEC and REC systems was deposition of an oxide layer, which inhibited significant corrosion. System filters and strainers are inspected for signs of corrosion products. Historically, those inspections have indicated an acceptable level of corrosion products.

Attachment 2

Changes to the License Renewal Application Related to
Aging Management Program
RAI Responses
Cooper Nuclear Station, Docket No. 50-298, DPR-46

1. Section 3.2.2.2.3 (Loss of Material due to Pitting and Crevice Corrosion), Item 2 states:

   "Loss of material from pitting and crevice corrosion for stainless steel piping and piping components exposed to a soil environment is managed by the Buried Piping and Tanks Inspection Program. The Buried Piping and Tanks Inspection Program will include (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, gray cast iron and stainless steel components. Buried components will be inspected when excavated during maintenance. An inspection will be performed within ten years of entering the period of extended operation, unless an opportunistic inspection occurred within this ten-year period."

   This is replaced with the following paragraph:

   "Loss of material from pitting and crevice corrosion could occur for stainless steel components exposed to a soil environment. At CNS, there are no stainless steel components exposed to a soil environment with an intended function for license renewal."

   Reference: Response to RAI B.1.3-1

2. Table 3.2.1 (Engineered Safety Features, NUREG-1801 Vol. 1), Item 3.2.1-4 states in the Discussion column:

   "The Buried Pipe and Tanks Inspection Program manages loss of material in stainless steel components exposed to soil."

   This is revised to read:

   "~~The Buried Pipe and Tanks Inspection Program manages loss of material in stainless steel components exposed to soil.~~ There are no stainless steel components exposed to soil at CNS with an intended function for license renewal."

   Reference: Response to RAI B.1.3-1

3. Table 3.2.2-6 (Standby Gas Treatment System) states the following for the restricting orifice line at the bottom Page 3.2-80:

Environment – "Soil (ext)"
Aging Management Programs – "Buried Piping and Tanks Inspection"
NUREG-1801 Vol. 2 Item – "V.D2-27 (EP-31)"
Table 1 Item – "3.2.1-4"
Notes – "E"

This is revised to read:

Environment – "~~Soil (ext)~~ Air – outdoor (ext)"
Aging Management Programs – "~~Buried Piping and Tanks Inspection~~ External Surfaces Monitoring Program"
NUREG-1801 Vol. 2 Item – "~~V.D2-27 (EP-31)~~ --"
Table 1 Item – "~~3.2.1-4~~ --"
Notes – "~~E~~ G"

Reference: Response to RAI B.1.3-1

4. Section A.1.1.3 (Buried Pipe and Tanks Inspection Program) states:

"The Buried Piping and Tanks Inspection Program is a new program that will include (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, gray cast iron, and stainless steel components."

This is revised to read:

"The Buried Piping and Tanks Inspection Program is a new program that will include (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, and gray cast iron~~, and stainless steel~~ components."

Reference: Response to RAI B.1.3-1

5. Section A.1.1.15 (Fatigue Monitoring Program) enhancement bullet 1, item 2 states:

"Repair or replace the affected locations before exceeding a CUF of 1.0."

This is revised to read:

"Repair or replace the affected locations before exceeding an environmentally adjusted CUF of 1.0."

Reference: Response to RAI B.1.15-1

6. Section A.1.1.18 (Flow Accelerated Corrosion Program) states:

"The Flow-Accelerated Corrosion (FAC) Program is an existing program that applies to safety-related and nonsafety-related carbon steel components and gray cast iron in systems containing high-energy fluids carrying two-phase or single-phase high-energy fluid greater than or equal to two percent of plant operating time per the criteria given in EPRI NSAC-202L."

This is revised to read:

"The Flow-Accelerated Corrosion (FAC) Program is an existing program that applies to safety-related and nonsafety-related carbon steel components and gray cast iron in systems containing high-energy fluids carrying two-phase or single-phase high-energy fluid ~~greater than or equal to two percent of plant operating time~~ per the criteria given in EPRI NSAC-202L."

Reference: Response to RAI B.1.18-2

7. Section A.1.1.18 (Flow Accelerated Corrosion) states:

"The FAC Program will be enhanced as follows.

- Update the System Susceptibility Analysis for the Flow-Accelerated Corrosion Program to reflect the lessons learned and new technology that became available after the publication of NSAC-202L Revision 1.

This enhancement will be implemented prior to the period of extended operation."

This is revised to read:

"The FAC Program will be enhanced as follows.

- Update the System Susceptibility Analysis for the Flow-Accelerated Corrosion Program to reflect the lessons learned and new technology that became available after the publication of NSAC-202L Revision 1.

- Program guidance documents will be revised to stipulate requirements for training and qualification of non-CNS personnel involved in implementing the FAC program."

- These~~is~~ enhancements will be implemented prior to the period of extended operation."

Reference: Response to RAI B.1.18-3

8. Section A.1.1.27 (Non-EQ Insulated Cables and Connections Program) states:

"This program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements, prior to the period of extended operation."

This is revised to read:

"This program will be implemented prior to the period of extended operation. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements to visually inspect accesible cables in an adverse localized environment at least once every 10 years, with the first inspection prior to the period of extended operation."

Reference: Response to RAI B.1.27-1

9. Section B.1.3 (Buried Pipe and Tanks Inspection) states:

"The Buried Piping and Tanks Inspection Program is a new program that will include (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, gray cast iron, and stainless steel components."

This is revised to read:

"The Buried Piping and Tanks Inspection Program is a new program that will include (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel~~,~~ and gray cast iron~~, and stainless steel~~ components."

Reference: Response to RAI B.1.3-1

10. Section B.1.15 (Fatigue Monitoring) Enhancement Section bullet (2) states:

"Repair or replace the affected locations before exceeding a CUF of 1.0."

This is revised to read:

"Repair or replace the affected locations before exceeding an environmentally adjusted CUF of 1.0."

Reference: Response to RAI B.1.15-1

11. Section B.1.18 (Flow-Accelerated Corrosion) states in the Program Description:

"The Flow-Accelerated Corrosion (FAC) Program is an existing program that applies to safety-related and nonsafety-related carbon steel components and gray cast iron in systems containing high-energy fluids carrying two-phase or single-phase high-energy fluid greater than or equal to two percent of plant operating time per the criteria given in EPRI NSAC-202L."

This is revised to read:

"The Flow-Accelerated Corrosion (FAC) Program is an existing program that applies to safety-related and nonsafety-related carbon steel components and gray cast iron in systems containing high-energy fluids carrying two-phase or single-phase high-energy fluid ~~greater than or equal to two percent of plant operating time~~ per the criteria given in EPRI NSAC-202L."

Reference: Response to RAI B.1.18-2

12. Section B.1.18 (Flow Accelerated Corrosion) states:

"The following enhancement will be implemented prior to the period of extended operation.

Elements Affected	Enhancement
1. Scope of Program	The System Susceptibility Analysis for the Flow-Accelerated Corrosion Program will be updated to reflect the lessons learned and new technology that became available after the publication of NSAC-202L Revision 1."

This is revised to read:

"The following enhancements will be implemented prior to the period of extended operation.

Elements Affected	Enhancement
1. Scope of Program	The System Susceptibility Analysis for the Flow-Accelerated Corrosion Program will be updated to reflect the lessons learned and new technology that became available after the publication of NSAC-202L Revision 1.
2 Monitoring and Trending	Program guidance documents will be revised to stipulate requirements for training and qualification of non-CNS personnel involved in implementing the FAC program."

Reference: Response to RAI B.1.18-3

13. Section B.1.24 (Non-EQ Bolted Cable Connections) states in Evaluation Item 1 (Scope of Program):

"Cable connections external to terminations at active or passive devices associated with non-EQ cables in scope of license renewal are part of this program. This program does not include the high voltage (> 35 kV) switchyard connections. In-scope connections are evaluated for applicability of this program. The criteria for including connections in the program are that the connection is a bolted connection that is not covered under the EQ program or an existing preventive maintenance program."

This is revised to read:

"Cable connections external to terminations at active or passive devices associated with non-EQ cables in scope of license renewal are part of this program. This program does not include the high voltage (> 35 kV) switchyard connections. In-scope connections are evaluated for applicability of this program. The criteria for including connections in the program are that the connection is a bolted connection that is not covered under the EQ program~~ or an existing preventive maintenance program~~."

Reference: Response to RAI B.1.24-1

14. Section B.1.24 (Non-EQ Bolted Cable Connections) states in Evaluation Item 4 (Detection of Aging Effects):

"Inspection methods may include thermography, contact resistance testing, or other appropriate methods based on plant configuration and industry guidance."

This is revised to read:

"Inspection methods may include thermography, contact resistance testing, or other appropriate <u>quantitative</u> methods based on plant configuration and industry guidance."

Reference: Response to RAI B.1.24-2

15. Section B.1.25 (Non-EQ Inaccessible Medium-Voltage Cable) states in the Program Description:

"The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that inspects the following underground medium-voltage cables.

- inaccessible medium-voltage cables between the station service water pumps (SWP-1A, 1B, 1C, and 1D) and the 4.16 kV safety switchgear
- inaccessible medium-voltage cables between 12.5 kV overhead loop and the fire pump motor (FP-MOT-E)
- inaccessible medium-voltage cables between the standby diesel (DG1 and DG2) to the 4.16 kV safety busses (1F and 1G)
- inaccessible medium-voltage cables between the 4.16 kV non-safety buses (1A and 1B) and the 161 kV control house power transformers (located in the 345 kV switchyard)"

This is revised to read:

"The Non-EQ Inaccessible Medium-Voltage Cable Program is a new program that inspects the following underground medium-voltage cables.

- inaccessible medium-voltage cables between the station service water pumps (SWP-1A, 1B, 1C, and 1D) and the 4.16 kV safety switchgear
- inaccessible medium-voltage cables between 12.5 kV overhead loop and the fire pump motor (FP-MOT-E)
- inaccessible medium-voltage cables between the standby diesel (DG1 and DG2) to the 4.16 kV safety busses (1F and 1G)
- ~~inaccessible medium-voltage cables between the 4.16 kV non-safety buses (1A and 1B) and the 161 kV control house power transformers (located in the 345 kV switchyard)~~"

Reference: Response to RAI B.1.25-1

16. Section B.1.29 (One-Time Inspection) states in the 4th paragraph of the Program Description:

"A representative sample will be selected from each unique material and environment combination covered under each of the activities. Each sample size will be based on Chapter 4 of EPRI document 107514, Age Related Degradation Inspection Method and Demonstration, which outlines a method to determine the number of inspections required for 90% confidence that 90% of the population does not experience degradation (90/90). Components with the same material-environment combinations at other facilities may be included in the sample."

This is revised to read:

"A representative sample will be selected from each unique material and environment combination covered under each of the activities. Each sample size will be based on Chapter 4 of EPRI document 107514, Age Related Degradation Inspection Method and Demonstration, which outlines a method to determine the number of inspections required for 90% confidence that 90% of the population does not experience degradation (90/90). ~~Components with the same material-environment combinations at other facilities may be included in the sample.~~"

Reference: Response to RAI B.1.29-1

17. Section B.1.22 (Metal-Enclosed Bus Inspection) states in Exceptions to NUREG-1801:

"The Metal-Enclosed Bus (MEB) Inspection Program will be consistent with the program described in NUREG-1801, Section XI.E4, Metal-Enclosed Bus Aging Management Program, with the following exception.

Elements Affected	Exception
3. Parameters Monitored or Inspected 4. Detection of Aging Effects	NUREG-1801 specifies the Metal Enclosed Bus Inspection Program for inspection of the internal portion of the MEBs, and specifies the Structures Monitoring Program for inspection of the external portion of the MEBs. The CNS Metal Enclosed Bus Inspection Program specifies visual inspection of the external surfaces of the MEB enclosure assemblies in addition to internal portions. [1]

Exception Note

1. Inspection of the external portion of MEB enclosure assemblies under the Metal Enclosed Bus Inspection Program instead of the Structures Monitoring program assures that effects of aging will be identified prior to loss of intended function. Visual inspections have been proven effective in detecting indications of loss of material."

This is revised to read:

"The Metal-Enclosed Bus (MEB) Inspection Program will be consistent with the program described in NUREG-1801, Section XI.E4, Metal-Enclosed Bus Aging Management Program, with the following exception.

Elements Affected	Exception
1. <u>Scope</u>	<u>NUREG-1801 program does not include management of aging effects for MEB enclosure external surfaces and elastomers. The CNS Metal Enclosed Bus Inspection Program provides for the management of the effects of aging for the external surfaces of the MEB enclosure assemblies and includes elastomers that are not routinely replaced. [1]</u>

	replaced. [1]
3. Parameters Monitored or Inspected ~~4. Detection of Aging Effects~~	~~NUREG-1801 specifies the Metal Enclosed Bus Inspection Program for inspection of the internal portion of the MEBs, and specifies the Structures Monitoring Program for inspection of the external portion of the MEBs.~~ NUREG-1801 program does not identify parameters monitored for external MEB enclosure surfaces or for elastomers. The CNS Metal Enclosed Bus Inspection Program specifies ~~visual inspection~~ monitoring the condition of the external surfaces of the MEB enclosure assemblies ~~in addition to internal portions~~ and the condition of exposed surfaces of elastomers that are not routinely replaced.. [1]
4. Detection of Aging Effects	NUREG-1801 program does not provide methods for detection of aging effects for external surfaces of MEB enclosure assemblies and elastomers. The CNS Metal Enclosed Bus Inspection specifies methods for detection of aging effects for these items. MEB enclosure assembly external surfaces will be visually inspected to manage loss of material and elastomer surfaces will be visually inspected to manage change in material properties at least once every 10 years. [1]

6. Acceptance Criteria	NUREG-1801 does not specify acceptance criteria for external surfaces of MEB enclosure assemblies or for elastomers. The CNS Metal Enclosed Bus Inspection Program specifies acceptance criteria for inspection of these items based on the Structures Monitoring Program for inspection of the external portion of the MEBs. The acceptance criterion for external surfaces of MEB enclosure assemblies will be the absence of pitting, cracks, flaking coatings, excessive rust, loose or missing bolts, peeling coatings, or wide-spread corrosion. The acceptance criterion for MEB elastomers will be the absence of cracks and gaps. [1]

Exception Note

1. Inspection of the external portion of MEB enclosure assemblies under the Metal Enclosed Bus Inspection Program instead of the Structures Monitoring program assures that effects of aging will be identified prior to loss of intended function. Visual inspections are the primary methods employed in the Structures Monitoring Program and have been proven effective in ~~detecting indications of~~ managing loss of material and change in material properties."

Reference: Response to RAI B.1.22-1